



Application

E-01345A-03-0437

PART 3 OF 3
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PART 1 OF 3 BAR CODED #00000000701

PART 2 OF 3 BAR CODED #0000108961

E 01345A-03-0437

Testimony
of
Ajit P. Bhatti

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DIRECT TESTIMONY OF AJIT P. BHATTI

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On Behalf of Arizona Public Service Company

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Docket No. E-01345A-03-___

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E-01345A-03-0437

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TABLE OF CONTENTS

1		
2	TABLE OF CONTENTS.....	i
3	I. INTRODUCTION AND SUMMARY	1
4	II. THE PWEC ASSETS	6
5	III. "USED AND USEFUL".....	8
6	IV. THE DECISION TO BUILD THE PWEC ARIZONA ASSETS	
7	WAS BASED ON A PRUDENT AND REASONABLE RESOURCE	
8	PLANNING PROCESS	24
9	A. APS PLANNING GOALS, CRITERIA AND PROCESS	24
10	B. PLANNING HISTORY—PAST AND RECENT IMPACTS	36
11	C. REGULATORY BACKGROUND TO APS	
12	RESOURCE PLANNING	59
13	V. ECONOMIC ANALYSES OF THE PWEC ASSETS.....	66
14	VI. THE PWEC ASSETS WERE PRUDENTLY AND TIMELY	
15	CONSTRUCTED, AND THEIR AS-BUILT COST WAS REASONABLE	68
16	VII. CONCLUSION.....	73
17	STATEMENT OF QUALIFICATIONS	APPENDIX A
18	ATTACHMENT AB-1	TIMELINE OF CRITICAL EVENTS
19	ATTACHMENT AB-2	2003-2012 L&R
20	ATTACHMENT AB-3	NON-PWEC TRACK B OFFERS
21	ATTACHMENT AB-4	BUSBAR COST ANALYSIS
22	ATTACHMENT AB-5	IRR OF PWEC ASSETS
23		
24		
25		
26		

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3 **DIRECT TESTIMONY OF AJIT P. BHATTI**
4 **ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
5 **(Docket No. E-01345A-03-____)**

6 I. **INTRODUCTION AND SUMMARY**

7 **Q. WOULD YOU PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

8 A. My name is Ajit P. Bhatti. I am Vice President of Resource Planning for Arizona
9 Public Service Company ("APS" or "Company"). My business address is 400
10 North Fifth Street, Phoenix, Arizona 85004.

11 **Q. IS YOUR PROFESSIONAL WORK EXPERIENCE AND EDUCATIONAL BACKGROUND SET FORTH IN APPENDIX A TO YOUR TESTIMONY?**

12 A. Yes.

13
14 **Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AT APS.**

15 A. As Vice President of Resource Planning, I am responsible for developing
16 generation plans and evaluating strategic initiatives for APS.

17
18 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?**

19 A. My testimony will describe the Pinnacle West Energy Corporation ("PWEC")
20 Arizona generating assets that APS seeks to acquire and include in its regulated
21 cost of service. These assets consist of the West Phoenix Combined-Cycle Units 4
22 and 5 ("WP-4" and "WP-5"), Redhawk Units 1 and 2 ("Redhawk-1" and
23 "Redhawk-2"), and Saguaro Combustion Turbine Unit 3 ("Saguaro CT-3"). I will
24 then discuss whether those assets have been, are, and will be "used and useful" in
25 serving APS customers. I next discuss the resource planning process that planned
26

1 for, designed, and evaluated the PWEC assets. Lastly, I testify concerning the
2 actual construction of the PWEC assets that are the subject of this proceeding.

3
4 **Q. WERE YOU PERSONALLY INVOLVED IN THE RESOURCE PLANNING**
5 **PROCESS FOR THE COMPANY DURING BOTH THE PLANNING AND**
6 **CONSTRUCTION OF PWEC'S ARIZONA GENERATING UNITS?**

7 A. Yes. The Redhawk and West Phoenix units were planned while I was head of the
8 Resource Planning Department at APS. These units, along with Saguaro CT-3,
9 were constructed while I was head of the Generation Planning Department at
10 PWEC. With the Arizona Corporation Commission's ("Commission") decision to
11 preclude divestiture and instead preserve APS as a traditional vertically-integrated
12 utility, I was transferred back to APS and assumed my present duties.

13 **Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?**

14 A. My testimony will show that:

- 15 • the PWEC assets were built to serve APS load, have done so
16 in the past, and are doing so currently;
- 17 • the PWEC assets are "used and useful" in meeting the
18 reliability and energy needs of APS customers both now and
19 in the future;
- 20 • the decision to build the PWEC assets was based on a prudent
21 and reasonable resource planning process in which the needs
22 of APS customers, rather than the profitability of PWEC, were
23 paramount;
- 24 • the PWEC assets were analyzed with sound economic
25 principles and were determined to be the best generation
26 option for our customers;
- the PWEC assets were timely constructed, and their as-built
cost is reasonable compared to similar generating assets of the
same vintage and as compared to alternatives available to
APS.

The PWEC assets were built to keep the lights on for APS customers. They have
already accomplished this purpose in 2001 through 2003. And they will continue to

1 provide an economic and reliable source of power for APS customers for decades
2 into the future if the Commission seizes this unique opportunity to place them into
3 the Company's rate base at their 2004 depreciated original cost. The alternatives to
4 the PWEC assets range from speculative to non-existent, as can be seen from the
5 recent Track B solicitation. Market alternatives are likely to be even less viable in
6 the future as the present glut of capacity quickly dries up and little or no new
7 capacity is added in the Southwest.

8 The PWEC assets provide more than just capacity and energy, although that is
9 clearly their primary function. They also provide APS operating flexibility, as well
10 as critical voltage support to the APS transmission system. The PWEC assets
11 themselves incorporate the most current environmental controls, preserve precious
12 groundwater resources through the use of effluent for cooling, and will partially
13 displace older, less efficient resources on the APS system, especially in the Valley.
14

15 Each of a series of APS Resource Planning decisions during the last decade
16 conclusively demonstrates the prudence, in fact the necessity, of constructing the
17 PWEC assets to serve APS. That period, the 1995-2000 planning horizon, which
18 encompassed the primary planning and construction commitment period for the
19 PWEC assets, takes on special significance. But throughout our planning activities
20 both at APS and at PWEC, our overriding concern has always been to satisfy the
21 traditional electric utility's essential purpose of maintaining reliability for our
22 customers at a reasonable and stable cost.

23 Resource planning decisions cannot be analyzed in a vacuum, but must be
24 understood within the historical context of their time. For the PWEC assets, it was
25 a time characterized by unprecedented regulatory uncertainty, economic disruption
26

1 on a regional and even national scale, and explosive demand growth within the
2 APS service area and, indeed, throughout the Southwest. I have prepared a
3 simplified timeline as Attachment AB-1 that depicts at least the major events in
4 Arizona, the region and nation, and for APS/PWEC planning and construction so
5 that it is possible to get a better understanding as to how all of these various pieces
6 fit together. I would add that despite these challenges, we succeeded not only in
7 reliably serving an expanding number of APS customers, but also protecting both
8 them and the Company from a wholesale market gone mad. And we are now
9 positioned to continue that record of service into the future with the strong market
10 hedge that a balanced, fuel-diverse portfolio of utility-owned and Commission-
11 regulated generation assets provides.

12 The construction of the PWEC assets was itself timely and skillfully managed to
13 produce reasonable as-built costs for APS customers, both as compared to other
14 generation options available to APS and as compared to reliance on wholesale
15 purchases, when and if available. And the savings from placing these assets into
16 the Company's rate base at their 2004 depreciated cost will provide additional
17 value to our customers. These approximate savings have been quantified in APS
18 witness Steven M. Wheeler's testimony as amounting to between \$214 million and
19 nearly \$500 million over the estimated 30-year life of the PWEC assets.

20
21 More specifically and in support of my conclusions, my testimony, along with the
22 testimony of Mr. Wheeler and Dr. William H. Hieronymus will demonstrate that:

- 23 • The current and projected APS reliability deficit was identified as far
24 back as 1998;

- 1 • The conclusion that APS would have to buy or build additional
- 2 capacity to meet this deficit was based on sound regional supply and
- 3 demand analyses;
- 4 • APS, and later PWEC, maintained a very flexible generation expansion
- 5 plan to address APS capacity needs, even at the expense of PWEC's
- 6 interests, throughout the planning and construction of the PWEC units;
- 7 • The PWEC assets were planned and built to meet the growing needs of
- 8 APS customers in a timely manner, were sited at locations where they
- 9 were needed to serve APS load and used state of the art technology;
- 10 • All of the PWEC assets were necessary to meet APS' peak load
- 11 requirements in the recent Track B solicitation;
- 12 • WP-4 and WP-5 serve Valley "must-run" requirements and provide
- 13 necessary operational benefits in addition to meeting the Company's
- 14 overall capacity and energy needs; and
- 15 • Cost-of-service treatment of the PWEC assets was shown by the
- 16 Company's economic analyses to potentially save APS customers over
- 17 \$519 million (net present value over the life of the assets).

18 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

19 A. My testimony is organized into seven sections, as follows:

- 20 • Introduction and Summary
- 21 • The PWEC Assets
- 22 • "Used and Useful"
- 23 • APS Resource Planning
- 24 • Economic Analyses of the PWEC Assets
- 25 • Construction Activities
- 26 • Conclusion

1 II. THE PWEC ASSETS

2 Q. **WHAT PWEC GENERATING ASSETS IS APS PROPOSING TO**
3 **ACQUIRE AND PLACE INTO ITS REGULATED RATE BASE?**

4 A. The PWEC generating assets at issue in this proceeding comprise five units having
5 a capacity of approximately 1700 megawatts ("MW"). These are WP-4 and WP-5,
6 Redhawk-1 and Redhawk-2, and Saguaro CT-3. As noted earlier, the first four of
7 these units are combined cycle generators, while the fifth unit is a small, simple
8 cycle combustion turbine.

9 Q. **WOULD YOU DESCRIBE EACH OF THESE UNITS AND THEIR**
10 **OPERATING HISTORY TO DATE IN MORE DETAIL?**

11 A. Yes.

12 *Redhawk-1 and Redhawk-2:*

13 The Redhawk Power Plant is located approximately 50 miles west of Phoenix near
14 the Palo Verde Nuclear Generating Station ("Palo Verde"). The Redhawk facility
15 consists of two nominally-rated 530 MW combined cycle gas turbine generating
16 units, for a total rated capacity of 1060 MW. Redhawk has access to the APS
17 transmission grid via two 500-kilovolt ("kV") transmission lines from the plant to
18 the Hassayampa switchyard. Both Redhawk-1 and Redhawk-2 use natural gas fuel,
19 and each has two GE Frame 7FA combustion turbines in combination with a single
20 Alstom steam turbine. And, in addition to being the latest in fossil generation
21 technology, the units are equipped with selective catalytic reduction ("SCR")
22 technology to comply with all requirements of the Clean Air Act's strict "best
23 available control technology" pollution control requirements. Redhawk also uses
24 wastewater effluent from cities in the metropolitan Phoenix area for primary
25 cooling rather than ground or surface water.
26

1 The facility entered operation in time to meet the summer of 2002 APS peak loads.
2 Both units have been providing their electric output to APS customers on an as-
3 needed and economic basis since their in-service. They are now under contract to
4 APS (along with WP-4, WP-5 and Saguaro CT-3) for the summer months through
5 2006 as a result of the Commission's recent Track B solicitation.

6 The unit equivalent availability factor ("EAF"), which is a standard industry
7 measurement of a generating unit's reliability, was approximately 86% through
8 May of 2003. Thus, the Redhawk units have already generated more than
9 4,039,251 MWH of electric energy.

10
11 *WP-4 and WP-5:*

12 These two new combined cycle units are located adjacent to APS' existing West
13 Phoenix Power Plant site near 43rd Avenue and Buckeye Road in Phoenix. WP-4 is
14 nominally-rated at 120 MW, whereas WP-5 is a nominally-rated 530 MW unit
15 similar to Redhawk. WP-4 and WP-5 are connected to the Valley 230 kV
16 transmission network system, which supports the Valley's "Reliability Must Run"
17 ("RMR") situation during summer peak. As explained later, both new units also
18 provide much needed overload protection and voltage support in Phoenix. Again
19 like Redhawk, the facility burns natural gas fuel. PWECC further paid the cost of
20 equipping APS' existing West Phoenix Unit 3 with SCR to further reduce
21 emissions from the site.

22 WP-4 was placed in service on June 1, 2001 and was essential in meeting APS'
23 load in that year. Since then, WP-4's output has been continuously serving APS
24 customer capacity and energy needs. A review of the historical operating log
25 indicates that WP-4 generated some 1,115,344 MWH of energy in 2001, 2002 and
26

1 2003 (through May). Virtually all of this energy was used by APS to displace less
2 efficient and/or more costly resources. WP-4's EAF was 94.3%, 95.4% and 97.6 %
3 during this same time period, which is far above the industry average for such
4 units.

5 WP-5 is estimated to be in commercial operation by July 2003. However, test
6 energy has been available to APS from WP-5 since March 15, 2003 on an
7 economic basis, and WP-5 can provide over 300 MW of capacity from its already
8 completed simple cycle turbine.

9
10 *Saguaro CT-3:*

11 Saguaro CT-3 is located adjacent to APS' existing Saguaro power plant site near
12 Red Rock, Arizona, which is approximately 30 miles north of Tucson. This simple
13 cycle, natural gas fired combustion turbine is 80 MW in size and is used for APS
14 peaking needs. Since Saguaro CT-3's commercial operation date of June 2002, the
15 unit has provided 66,515 MWH of energy through May 31, 2003. Saguaro CT-3
16 has directly displaced either less efficient generation or more costly market
17 purchases by APS during that period. Its EAF through May of 2003 has been over
18 98%.

19
20 III. "USED AND USEFUL"

21 Q. **WHAT IS YOUR UNDERSTANDING OF THE CRITERIA FOR A PLANT
22 TO BE CONSIDERED "USED AND USEFUL"?**

23 A. My understanding of the criteria to be considered in determining if a plant is "used
24 and useful" is fairly straightforward. If there is a functional need for the plant's
25 output, then the plant meets the criteria for being used and useful. This was the test
26 used by the Commission when determining whether or not to include Palo Verde in

1 the Company's rate base and, I am told, all of the rest of the APS facilities
2 previously incorporated into its rate base.

3
4 **Q. ARE THE PWEC UNITS "USED AND USEFUL"?**

5 A. Yes. My testimony has already detailed both how APS has received and is
6 presently receiving power from these generating plants. And that power has been,
7 is, and will be necessary to serve APS customers. During 2002, PWEC provided
8 nearly 20% of the total capacity used to serve APS load. Although the Valley
9 reliability contribution by the PWEC units (15.4%) was somewhat less than their
10 overall contribution to APS needs, there were no practical alternatives to WP-4.
11 And for 2003, the PWEC contribution will be higher with the addition of WP-5.
12 Looking into the near future, estimated APS retail load plus a modest reserve
13 requirement of 15% (some of the merchant power plant intervenors in the recent
14 Track B proceeding argued for a higher reserve margin of at least 17-18%) for
15 2004 is 6810 MW. Even counting all of the recent Track B acquisitions of power
16 and including all of the PWEC generation sought to be included in the Company's
17 rate base, APS will need yet additional generation resources before this rate filing
18 is decided. Thus, its reserve margin will not be "razor thin," as characterized by the
19 Commission in the case of Palo Verde, but nonexistent. And, again including the
20 PWEC assets, the deficit grows in future years, reaching at least 1130 MW by
21 2007, the year following the end of the present contract between APS and PWEC
22 covering these generating facilities. Table 1 below provides the APS system Loads
23 and Resources ("L&R") calculation for the years 2003 through 2007. A more
24 detailed portrayal of the full L&R calculation for these years, as well as through
25 2012, is on Attachment AB-2. Please note that the larger potential deficit shown on
26 Attachment AB-2 (1557 MW) is dependent upon whether or not Salt River Project

1 ("SRP") continues its present long-term contract with the Company, a contingency
2 I discuss later in my testimony.

3 **TABLE 1**

4 **APS Summer Supply & Demand Balance**
5 **Includes Track B Purchases**

6

	2003	2004	2005	2006	2007
7 A. TOTAL LOAD REQUIREMENTS	6,448	6,810	7,092	7,382	7,685
8 B. EXISTING GENERATION	3,927	3,953	3,948	3,975	3,975
9 C. EXISTING CONTRACTS	<u>830</u>	<u>837</u>	<u>844</u>	<u>852</u>	<u>860</u>
10 D. ADDITIONAL NEEDS (B+C-A)	(1,691)	(2,021)	(2,300)	(2,555)	(2,850)
11 E. NEW RESOURCES					
12 PWEC	1,700	1,700	1,700	1,700	1,700
13 PPL's SUNDANCE PURCHASES	112	150	150		
14 SHORT-TERM PURCHASES	125	0	0	0	0
15 F. TOTAL RESOURCES OVER / (UNDER)	250	(161)	(432)	(837)	(1,130)

16

17 **Q. IS THE "USED AND USEFUL" CASE ALSO COMPELLING IF YOU**
18 **EVALUATE EACH OF THE PWEC ASSETS INDIVIDUALLY?**

19 **A.** Yes, although APS does not propose to acquire the units on a piecemeal basis.
20 Each of the PWEC assets provides a unique contribution to meeting APS customer
21 needs

22 **Q. PLEASE EXPLAIN.**

23 **A.** I will begin with WP-4 and WP-5. As I mentioned in my description of these units,
24 they provide support for the Company's RMR requirements in the Valley, where
25
26

1 the great majority of the Company's customers reside, as well as contribute toward
2 needed generation capacity for the entire APS system.

3
4 **Q. BEFORE GOING FURTHER, COULD YOU EXPLAIN WHAT RMR MEANS?**

5 A. RMR refers to the need for generation within a "load pocket," to operate at certain
6 times of the year for reliability reasons because of the inability to import that
7 marginally more economic generation into the load pocket. More specifically, a
8 "load pocket" (sometimes also referred to as a "transmission constrained" or
9 "import constrained" area) occurs when all the local demand within the load pocket
10 cannot be served by importing power, thus requiring the use of some local
11 generation. During certain hours of the year, the Phoenix area (i.e., the Valley) is
12 such a transmission-constrained area. It consists of an integrated transmission and
13 sub-transmission network serving both APS and SRP load, as well as the
14 generating resources of these respective utilities within the Valley.

15
16 **Q. ARE LOAD POCKETS A NEW PHENOMENON OR EVIDENCE OF INADEQUATE TRANSMISSION FACILITIES?**

17 A. Neither is the case. Load pockets generally exist wherever there is concentrated
18 load and are as old as the electric industry itself. Similarly, it is almost universally
19 more cost effective to build local generation than to build enough transmission
20 capacity to squeeze out the relatively few hours a year a load pocket is constrained,
21 even assuming it were easier to site transmission than generation in an urban area.
22 This is even more the case when the local generation was constructed years ago
23 and is now largely depreciated.

24 Local generation also provides necessary voltage support, regulation, and overload
25 protection. By voltage support, I mean that local generation allows APS to keep
26

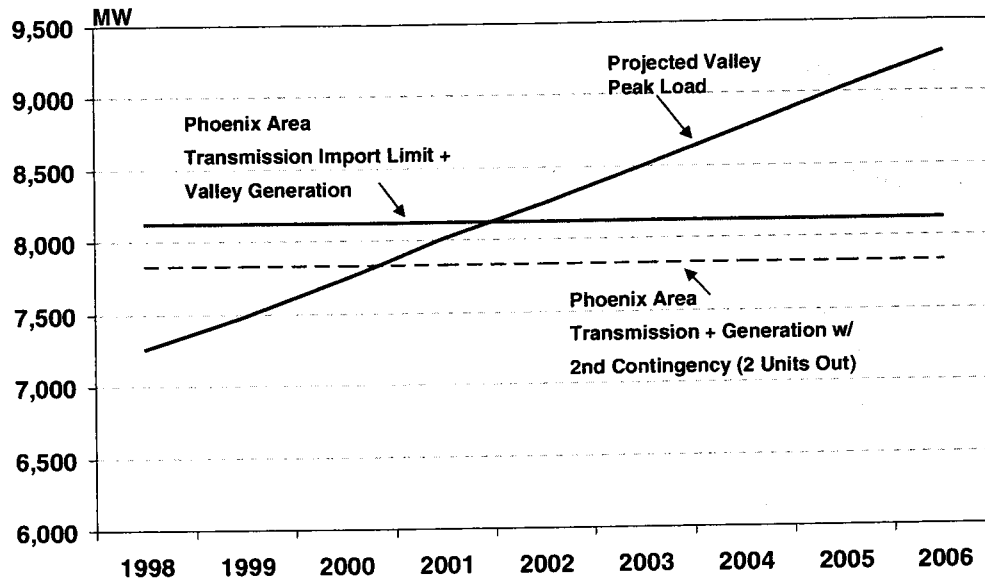
1 voltage from collapsing in the Valley in much the same way booster pumps for a
2 gas pipeline or water system are necessary to maintain the pressure needed to
3 operate those utility systems. A loss of voltage support could not only bring down
4 the APS system within the Valley, it could cause severe damage to both customer
5 and utility equipment. But unlike booster pumps, which merely pressurize
6 whatever existing commodity is put in them, local generation also produces
7 additional capacity and energy. By doing so, it "unloads" the strain on transmission
8 lines into the load pocket, thus both protecting those lines from overload and
9 permitting additional imports over them. "Regulation" is the ability to prevent wide
10 fluctuations in voltage that can have some of the same harmful impacts as a voltage
11 collapse. Voltage support, regulation, and overload protection are critical during
12 peak times and beneficial all the time, even during non-constrained times of the
13 year, and would be necessary even if no transmission (import) constraint existed.

14 **Q. HOW DOES THE VALLEY RMR REQUIREMENT RELATE TO THE**
15 **CONSTRUCTION OF WP-4 AND WP-5?**

16 **A.** APS has continuously reviewed the Valley's load requirements and transmission
17 import capabilities. An RMR study was prepared in 1997 to determine the need for
18 future must-run generation in the Valley in conjunction with the Company's
19 overall generation supply needs. Although the 1997 RMR study (and even later
20 studies in 1998 and 1999) underestimated both the urgency and magnitude of the
21 growing RMR situation in Phoenix, Figure 1 was prepared from the data available
22 at the time and shows the Valley Loads and Resources projection for the ten-year
23 period. As can be seen, a substantial amount of additional capacity was required
24 within the Phoenix area to reliably serve APS customers beginning as early as
25 2001.

FIGURE 1

Phoenix Area Generation & Transmission Import Limits



Q. HAS THE COMPANY RECENTLY BEEN ASKED TO CONDUCT A NEW RMR STUDY?

A. Yes. The Company completed another RMR study in early 2003. That study was done in conjunction with Commission Staff and at Staff's urging.

Q. DOES THIS RECENT RMR STUDY OF THE PHOENIX AREA SUPPORT THE CONTINUED NEED FOR WP-4 AND WP-5?

A. Yes, most definitely. The 2003 RMR study assumed that all of the substantial improvements to the Phoenix-area transmission system were completed and available beginning in the summer of 2003. These improvements include, most significantly, a new 500 kV line from Palo Verde to the Rudd substation, which increases the import capability into the Phoenix area by 1200 MW (APS' share is 50%, or 600 MW). A number of other transmission facility upgrades and additions

1 were factored into the RMR study, including projects planned for 2004 and 2005.
2 Despite these enhancements, the study specifically concluded that APS would
3 require within the Valley an additional 365 MW in 2003, 486 MW in 2004 and 554
4 MW 2005. This capacity would be in addition to the 660 MW APS already owns at
5 West Phoenix and Ocotillo.

6
7 **Q. HOW COULD APS MEET THIS RMR NEED FOR THE VALLEY?**

8 A. As the study itself concludes, additional APS transmission to relieve the RMR
9 situation is neither economic nor desirable for operational reasons. Thus, these
10 additional resources would need to be obtained from uncommitted SRP generation
11 (if any) located within the Phoenix area, from more remote generation delivered
12 over uncommitted SRP transmission capacity (if any), by newly constructed local
13 generation, or by the already-built PVEC resources of WP-4 and WP-5.

14 Looking at each of these options, it is clear that building new non-PVEC
15 generation is not an option even for 2004 and 2005. And no non-PVEC RMR bids
16 for Phoenix covering any years after 2005 were even submitted by merchant
17 generators in the Track B proceeding. The option of purchasing any uncommitted
18 generation or transmission capacity from SRP is technically feasible but is an
19 unlikely and impractical option. Although SRP and APS are obligated to and
20 always have cooperated in a crisis situation, it appears doubtful that SRP would
21 enter into significant firm transmission or generation contracts when it is planning
22 to build an additional 825 MW of generation within the Phoenix constraint to meet
23 its own needs. This was confirmed by the fact that SRP did not submit an RMR bid
24 in the recent Track B proceeding even though it would have been bidding against
25 APS' older and less efficient Ocotillo and West Phoenix units with PVEC as its
26 only meaningful competitor. In that regard, I must also note that our existing long-

1 term agreement with SRP, the so called "Territorial and Contingent" ("T&C")
2 agreement may be cancelled by SRP beginning December 31, 2006 with three
3 year's notice to APS. Although not itself an RMR resource, the T&C agreement's
4 expiration would increase APS' unmet needs, as shown in my Attachment AB-2,
5 by approximately another 400 MW beginning in 2007 (which is after expiration of
6 the present PVEC contract with APS). And even if remote generation could be
7 imported over SRP lines, such generation would not provide the same operational
8 benefits, such as voltage support, as would local generation. Thus, for all practical
9 purposes, APS has no viable alternative to WP-4 and WP-5, both of which are
10 needed to maintain reliability in the Phoenix area.

11 **Q. WHY DID YOU SELECT THE SITE ADJACENT TO THE EXISTING WEST**
12 **PHOENIX POWER PLANT FOR NEW IN-VALLEY GENERATION?**

13 A. We began a series of studies in 1998 that led to the final decision in April 1999 to
14 build WP-4 and WP-5. We focused primarily on the West Phoenix facility because
15 APS or an affiliate already owned the site and its surrounding land, PVEC could
16 use existing infrastructure, and it was believed that we could obtain the necessary
17 permits to build additional capacity. We also knew we could readily upgrade the
18 transmission system around the plant to get the power onto the unconstrained side
19 of the Phoenix-area network. In the Spring of 1999, there were no planned
20 merchant plants within the Phoenix constraint, and even today, there are no new
21 units planned except those built by SRP and PVEC.

22 **Q. ARE REDHAWK 1 AND 2 OR SAGUARO CT-3 RMR UNITS?**

23 A. No. They are not within the Valley "load pocket."
24

25 **Q. THEN WHY WERE THEY CONSTRUCTED?**
26

1 A. Saguaro CT-3 was a viable economic option for our 2000 - 2002 reliability
2 program during the California energy crisis and also made sense in view of the
3 dearth of peaking capacity being constructed by merchant generators in the region.
4 This decision was made possible because of equipment availability on an expedited
5 schedule and was an obvious bargain compared to paying the continued high cost
6 of temporary generation such as PWEC had to bring on-line in 2001 to serve APS
7 customer load growth pending completion of Redhawk and WP-5. Indeed, the cost
8 of retaining temporary generation just for 2002 would have equaled nearly half the
9 cost of building a thirty-year asset in the form of Saguaro CT-3.

10 We decided to build the Redhawk units because our planning analyses indicated a
11 critical need for new capacity in Arizona and the Southwest that was not then being
12 met in any other way, either through new construction in Arizona or additional
13 imports of power into the region. Indeed, each of these units, along with the West
14 Phoenix RMR units, were to eliminate the overall generation deficit identified via
15 our planning studies in 1998-99 to serve our customers' demand growth in
16 Arizona.

17
18 The construction of the Redhawk units near Palo Verde was a result of a very
19 detailed evaluation of market conditions during its planning stages in 1998-99, as
20 well as a thorough consideration of the existing and projected transmission network
21 in Arizona. We also considered gas supply, water supply, and most importantly,
22 APS customer and load growth.

23 Specifically, in mid to late 1998, we prepared numerous planning studies related to
24 market supply and demand in the Southwest and Western Electricity Coordinating
25 Council ("WECC") region. We made an assessment of merchant generators'
26

1 activities, simulated the economics of new combined-cycle and simple-cycle units
2 at various locations in the WECC, and reviewed various potential sites in Arizona
3 for possible generation locations. All of these analyses were done in conjunction
4 with the expertise and knowledge gained from our previous ongoing planning
5 process and related studies, which I again address in the Resource Planning section
6 of my testimony. Based on all this and other parallel resource acquisition strategies
7 contemplated at that time, we developed a flexible schedule calling for 1500 to
8 2000 MW of new generation near the Palo Verde hub. This location would allow
9 this new generation to both serve APS load and access the market for off-system
10 sales during periods when it was not needed by APS. Our original plans called for
11 newly built generation in the 2003 to 2007 timeframe, with the potential for further
12 variations of that schedule. When it became clear that, for a variety of reasons I
13 discuss later, we would not be able to purchase any additional generation capacity
14 from existing jointly-owned power stations and the wholesale market appeared in
15 total disarray, we accelerated our construction schedule. This decision eventually
16 brought Redhawk-1 and Redhawk-2 on line in 2002, which was when they were
17 needed by APS but somewhat before our studies showed they would be the most
18 profitable for PWEC.

19 **Q. ARE YOU SAYING THAT ALL OF THE PWEC GENERATING ASSETS**
20 **WERE CONSTRUCTED PRIMARILY TO SERVE APS LOAD?**

21 **A.** Absolutely. Since late 1998, Redhawk and West Phoenix have been a part of the
22 APS resource plan. The schedule for their construction varied with load projections
23 and with the potential availability of non-build resource options such as the
24 acquisition of additional shares of Palo Verde and Four Corners Power Plant
25 ("Four Corners"), discussed later in my testimony. But the purpose for their
26 eventual construction was clear throughout. PWEC generation growth has always

1 been inexorably linked to APS needs rather than the interests of a pure merchant
2 generator.

3
4 **Q. DO YOU HAVE ADDITIONAL EVIDENCE TO SUPPORT THIS**
5 **ASSERTION THAT THE PWEC ASSETS HAVE BEEN DEDICATED TO**
6 **SERVE APS?**

7 A. Yes. The location of the units also demonstrates that they were built with APS
8 customers in mind. If we had been building these units as a pure "merchant
9 generator," we would have chosen to build them in or closer to California. We
10 produced numerous studies indicating that a higher potential profit could be
11 achieved by locating a plant in or close to California than in central Arizona. But
12 we chose to stay close to our native load because we were building the PWEC units
13 with the goal of first serving APS customers. And unlike some of the other plants
14 built near Palo Verde, Redhawk was specifically planned to coincide with APS'
15 publicly-announced transmission upgrades—not west to California, but east to the
16 Valley—that would allow that facility adequate access to APS load.

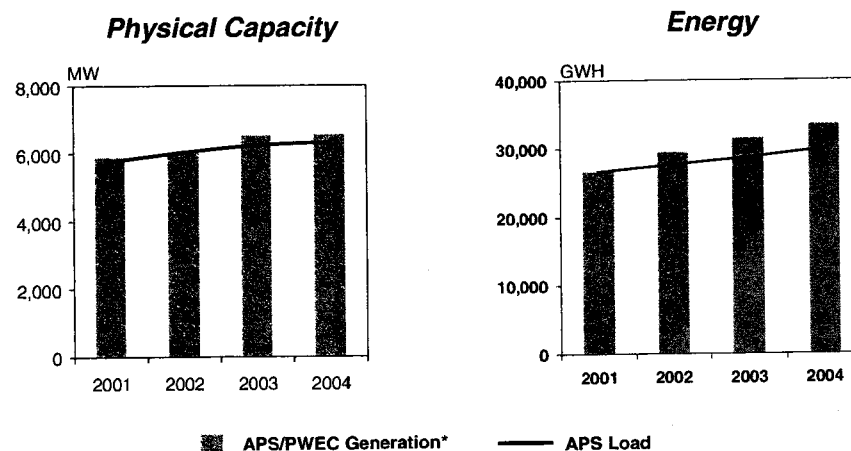
17 Even though our planning studies suggested a significant financial gain for
18 Pinnacle West, in general, and PWEC, in particular, by selling PWEC's generation
19 forward to California, Pinnacle West management decided to forego those
20 opportunities. Thus, the marketing of power from the PWEC units, or rather, the
21 clear decision by PWEC not to market power from those units also indicated that
22 we were reserving this capacity first and foremost to meet APS load. This was at
23 the time when California prices were at their highest and that state's Department of
24 Water Resources was scrambling to sign contracts at very high prices in early
25 2001. And when it appeared that the California market debacle was spreading to
26 other Western states, APS and PWEC developed a proposed purchase power
 agreement that would have assured a stable price and supply for APS customers

1 using both APS existing generation and the PWEC units. This was done even
 2 though it precluded PWEC from earning above-cost returns over the life of the
 3 PWEC assets. These were not the actions of a merchant generator answerable only
 4 to its shareholders but the sober planning of a responsible utility attempting to
 5 discharge its public service obligation.

6 Finally, I have included as Figure 2 a copy of a graph from our presentation to
 7 ratings agencies on behalf of PWEC in early 2001. This was again when the
 8 opportunities in California and elsewhere in the West were very profitable. And yet
 9 the graph provided at the time shows without question that the PWEC generation
 10 would only market whatever capacity and energy that was not needed by APS,
 11 which always had first call on all of PWEC's resources.

12
13 **FIGURE 2**

14
15 **PWEC - Generation Growing In Pace
with APS Load**



- APS/PWEC Generation* — APS Load
- Adequate capacity designed to meet APS' growing needs
- Power Marketing sales of surplus generation to other markets enhance profit margins during Q1, Q2, Q4

*Includes spot and long-term contracts

1 Q. SINCE NEITHER REDHAWK NOR SAGUARO ARE RMR UNITS,
2 COULD THE COMMISSION NONETHELESS IGNORE REDHAWK AND
3 SAGUARO AND REQUIRE APS TO ACQUIRE ADDITIONAL
4 PURCHASED POWER TO COVER THE GENERATION SUPPLY
5 DEFICIT STILL REMAINING AFTER CONSIDERATION OF WP-4 AND
6 WP-5?

7 A. No. To do so would ignore the history as to why these units were built and the
8 prudence of the resource planning that led to those decisions. It would also be
9 inequitable for the reasons discussed by APS witness Steve Wheeler in his direct
10 testimony.
11

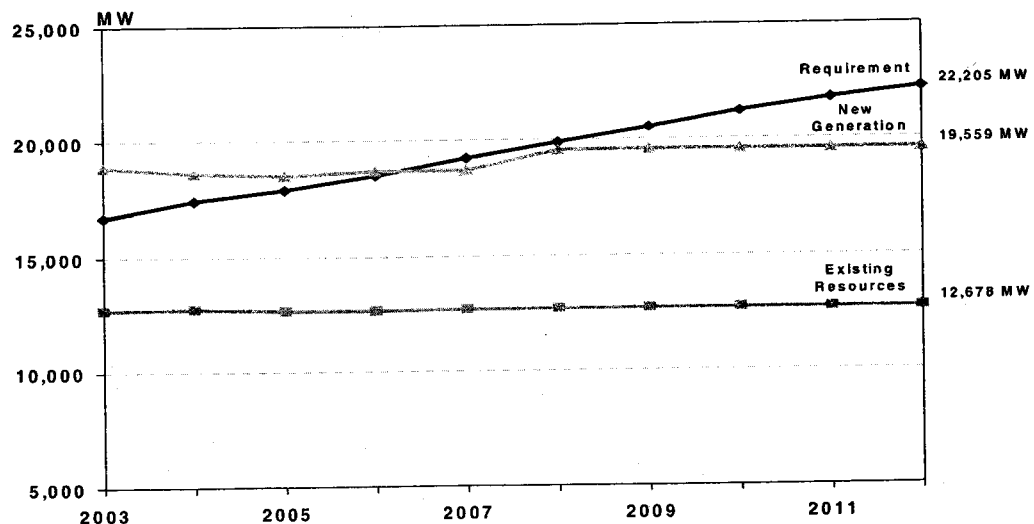
12 With those caveats, let me also say that I have very significant doubts about both
13 the availability and price of the well over 1000 MW of additional purchased power
14 that such a Commission action would necessitate. You have to remember that
15 without the PWEK assets sought to be included in APS rate base, and most
16 specifically Redhawk-1, Redhawk-2 and Saguaro CT-3, the Company could not
17 have met its overall reliability needs, as determined by the Commission in Track B,
18 for even 2003. (See Attachment AB-3.) And as we go out a few years, the lack of
19 interested merchant generators in committing to APS was even more evident.
20 They, like our own forecasts, apparently see a turnaround in today's soft market in
21 the not too distant future and likely do not want to commit resources today that will
22 be much more valuable in a few years. Redhawk and Saguaro CT-3 provide asset-
23 backed hedges against this market uncertainty and will generate off-system sales
24 margins that will be especially beneficial to APS customers during periods of rising
25 market prices, thus increasing their value in the future.
26

23 Q. WILL THE REGIONAL DEMAND/SUPPLY BALANCE IMPROVE IN
24 THE YEARS FOLLOWING COMPLETION OF THE PRESENT RATE
25 PROCEEDING SUCH THAT THE COMMISSION CAN SAFELY RELY
26 ON FUTURE "TRACK B-TYPE" SOLICITATIONS TO MEET APS
CUSTOMER NEEDS?

1 A. No. Although more new merchant generation has been or is in the process of being
2 constructed in Arizona than could have been anticipated in late 1998 and
3 throughout 1999, Arizona is a growing state and the Southwest a growing region.
4 Electricity demand growth calls for over 600 MW per year of new generation
5 needs in Arizona alone for several years to come. Yet, no new generation has been
6 announced recently in Arizona. Depending on how fast the region and especially
7 California recover from the recent economic slow down, the new generation
8 currently built by others in Arizona likely will be absorbed by the projected
9 demand growth within the next two to three years. This, in turn, would lead to a
10 potential shortage and significantly higher prices by 2006, if not sooner. I have
11 provided below in Figure 3 a graphic representation of the combined Arizona
12 estimated loads and resource balance from 2003 through 2012. Dr. Hieronymus
13 also testifies in this regard and has described a generation "boom and bust"
14 analysis from which he postulates the next generation supply shortfall and
15 corresponding price shock at around the same 2006-07 period.

16 **FIGURE 3**

17 **Arizona Summer Supply & Demand Balance**



1 Figure 3, which depicts the Arizona generation requirement, uses demand forecasts
2 recently provided by Western utilities to the WECC, formerly called the Western
3 Systems Coordinating Council ("WSCC"), plus an estimated 15% reserve margin,
4 which is the same margin APS uses in its individual studies. The existing
5 generation includes all the generation owned by Arizona utilities, including their
6 allocation of hydro-electric resources and outside purchased power contracts. It
7 also assumes all the new generation presently under construction in Arizona is
8 completed by 2004 and that SRP's Santan plant (825 MW) will be completed by
9 2008. We currently estimate that approximately 2800 MW of this new generation
10 has been or will be sold to out-of-state utilities by their merchant generator owners.
11 With these assumptions, it is estimated Arizona will require more than 2600 MW
12 of additional new generation over the next ten years even with all of PWEC's
13 Arizona generation and the new SRP generation. If Tucson Electric Power ("TEP")
14 goes forward with its planned expansion of Springerville, that would improve the
15 overall Arizona situation by about 500 MW, assuming none of that additional
16 capacity is sent to out-of-state buyers.

17 **Q. ASIDE FROM THE NEED FOR THE PWEC ASSETS IN SERVING APS**
18 **PEAK LOAD, IS THERE ADDITIONAL EVIDENCE THAT SUCH ASSETS**
19 **WOULD BE "USED AND USEFUL" IF ACQUIRED BY APS AND**
20 **DEDICATED TO SERVING APS CUSTOMERS?**

21 **A.** Yes. These assets fit well into the APS dispatch model. The energy produced from
22 these units is more economical than existing APS gas and oil units, and some of the
23 Company's purchased power contracts. Typically, the new units are dispatched
24 after the existing APS coal and nuclear units but before the existing APS gas and
25 oil units. This was no mere coincidence. The PWEC units were designed to fill a
26 specific duty role in the combined APS/PWEC dispatch cycle used to serve APS
customers in the most economically efficient and reliable fashion possible.

1 Second, the combined cycle technology used for most of the PWEC assets also
2 provides a versatile generation base in that it can operate in discrete phases. That
3 means there will be very few instances when the whole plant is rendered unusable
4 for serving APS customers. The ability to function either as a base load plant, a
5 cycling unit, or even a peaking plant gives the owner of these assets both flexibility
6 and reliability.

7 Third, from a capacity mix perspective, the PWEC assets fit well with APS'
8 existing generation. The existing generation capacity owned by APS is 28%
9 nuclear, 43% coal, and 29% oil and gas. The coal and nuclear capacity for the APS
10 system is operated primarily as base-load duty cycle, which means that it is
11 operated for customers whenever it's available. In contrast, the existing gas and oil
12 units normally operate as peaking duty cycle generators and are operated only
13 during heavy customer demand periods. With the PWEC assets, these percentages
14 are more balanced. The combined APS and PWEC generation capacity will be
15 20% nuclear, 30% coal, and 50% natural gas and oil.

16 Finally, from the energy production perspective, the PWEC assets also improve our
17 historical reliance on base-load coal and nuclear energy significantly. The energy
18 mix of APS' existing units typically has been 38% nuclear, 55% coal and 7% oil
19 and gas. With the PWEC assets, these percentages are more balanced. The energy
20 output from these units in 2004, for example, will be 31% nuclear, 44% coal, and
21 25% gas and oil. The wisdom of not relying too heavily on any one fuel has been
22 proven many times, but it is a lesson that can be overlooked because of the
23 overriding preoccupation with natural gas in today's market. While all of the
24 incremental capacity built by PWEC is fueled by natural gas, our planning
25 assumptions had always been that we would combine the natural gas-fired units
26

1 with the existing APS coal and nuclear capacity to create this more-balanced
2 portfolio.

3
4 IV. THE DECISION TO BUILD THE PWEC ARIZONA ASSETS WAS BASED ON
5 A PRUDENT AND REASONABLE RESOURCE PLANNING PROCESS

6 A. *APS Planning Goals, Criteria and Process*

7 Q. **WHAT ARE THE GOALS OF APS RESOURCE PLANNING?**

8 A. The primary goals of APS Resource Planning are to provide our customers with an
9 adequate supply of reliable power at a reasonable cost and at a reasonable level of
10 risk. In this context, the term "reasonable level of risk" means that there must be a
11 very high probability that the supply of power for our customers will be adequate,
12 will be reliable, and will be at a reasonable cost. APS customers want the lights to
13 go on and the machinery to work when they throw the switch. They are neither
14 merchant generators nor energy speculators, and they do not want to be
15 responsible, or have their local utility make them responsible, for the risks of such
16 enterprises.

17 Q. **WHAT ARE THE PRINCIPAL MEANS OF ACHIEVING THIS GOAL?**

18 A. First, we strive to produce a flexible plan that can be adapted to fit changing
19 circumstances. Predicting the future is always a matter of estimating probabilities,
20 not measuring certainties. Market forces, economic trends, technological change
21 and regulatory forces, all of which are beyond our control, can and do impact
22 events in often unanticipated and even counter-intuitive ways. Thus, we develop
23 scenarios for a whole range of possibilities. When new circumstances occur, as
24 they inevitably do, we want to be ready with alternatives, whether they be
25 modifications of one kind or another to our already existing plans or whole new
26 approaches. This business mindset has been a key corporate strategy of APS and its

1 parent, Pinnacle West, throughout the years-long process of electric industry
2 restructuring in this country and in Arizona.

3 Second, we build our plans around our existing and proven portfolio of generation
4 resources. APS has relied heavily since the 1970s on base-loaded coal and nuclear
5 capacity. All of our plans began with long-range forecasts for those base-load
6 units, as augmented by existing long-term purchased power contracts.

7
8 Third, and again building on the excellent performance of our base-load
9 generation, we strive for a flexible and diverse fuel mix. Relying too heavily on
10 any one fuel can expose the company and its customers to unacceptable and
11 unnecessary supply, price and regulatory risks.

12 Fourth, we seek to create a diverse portfolio of generating assets in terms of size
13 and location of the individual units. Ideally, we would not wish to depend on any
14 single generating unit for a large percentage of our capacity. Although siting
15 availability and system operating limits impact the location of plants, we also look
16 for resources in different geographic areas relative to APS load centers that can
17 potentially supply our customers over a variety of transmission links. This
18 provides both economic and reliability benefits for APS customers.

19
20 Fifth, we are constantly seeking to improve our load forecasting expertise to
21 identify and incorporate the most predictive data for generation planning and to
22 better refine our generation and system modeling capabilities. In doing so, we
23 factor in the anticipated impact of known demand-side management ("DSM") and
24 energy reduction programs. We also estimate the impact in the aggregate of
25 demand/energy responses to price.
26

1 **Q. WHAT CRITERIA DO YOU USE TO MEASURE THESE GOALS?**

2 A. The criteria include measurements of reserve margin, "busbar" costs (total cost per
3 kWh of generation at the "bus," or where the generator is interconnected to the
4 transmission system), studies of the long-term cost of various alternatives, and the
5 impact of all three on long-term APS revenue requirements. We also try to keep
6 the risk to customers as low as possible. We do this by establishing resource
7 diversity targets (which I have discussed above in the context of fuel source, unit
8 location, and unit type and size) and by combining a solid foundation of owned
9 resources with a mix of long and short-term market purchases.

10 **Q. WILL YOU PLEASE DESCRIBE THE APS RESOURCE PLANNING**
11 **PROCESS AND THE PLANNING TECHNIQUES THAT YOU USE?**

12 A. At APS, the resource planning process consists of both a technical analysis stage
13 and a management decision stage. The former involves several discrete analyses
14 that are then integrated into a specific recommendation or series of
15 recommendations to upper management at APS. These technical analyses include:
16 (1) project-specific economics; (2) Western markets regional resource planning
17 studies; (3) wholesale market price forecast studies; (4) busbar cost determinations;
18 and (5) long-range fuel and purchased power cost forecasts. These allow APS to
19 determine how a prospective generating project fits into the Company's existing
20 resource package, what are its opportunities to sell power off-system to reduce
21 busbar costs to APS consumers, what are APS' opportunities to buy power (both
22 short and long-term) rather than construct new generation, and what is the price
23 and supply risk for both the proposed generating project and its alternatives. A
24 more detailed description of these five separate but interrelated analyses is set forth
25 below.
26

- 1 • *Project-specific economics.* We analyze the value of any new
2 project – whether to “buy or build” – based on discounted cash
3 flows under a variety of assumptions. This analysis allows us to
4 determine a project’s expected internal rate of return (“IRR”) and
5 its incremental contribution to earnings (in the case of an
6 unregulated project) or its incremental value in reducing revenue
7 requirements (in the case of a regulated project). Please note that
8 these are complimentary concepts. The same project that would
9 maximize profits for a merchant generator (because its costs are
10 that much less than the expected value of its output) will
11 minimize revenue requirements in a regulated cost-of-service
12 environment, again because its costs are below the costs of
13 alternatives. It is generally the case that any project that has an
14 IRR greater than the cost of equity will produce savings to
15 consumers under cost-of-service regulation. The analysis
16 necessarily takes into account revenues and margins from both the
17 retail and wholesale markets. Indeed, the ability of a project to
18 effectively compete in the wholesale market during those periods
19 of the day or year when it is not being used to serve retail load has
20 progressively taken on more importance with the development of
21 a more competitive wholesale market in the late 1990s.
- 22 • *Regional Resource Planning Studies.* In a competitive wholesale
23 generation market, regional studies assume a critical role for the
24 regulated utility as well as an unregulated generation company.
25 In the wholesale market, power costs are largely determined by
26

1 the regional supply-demand generation balance and the region's
2 transmission adequacy. Traditionally, utility resource planning
3 focused primarily on the individual utility by simulating a single
4 electrical system such as that of APS. Beginning in the mid-
5 1990s, APS began to put more emphasis on regional simulations,
6 which analyze the interaction of large-scale interconnected
7 systems like the WECC. This kind of analysis allowed us to
8 determine the power supply and demand situation for the entire
9 region, and to evaluate projected regional demand in the context
10 of regional transmission and generation resources.

- 11 • *Wholesale Market Price Forecast Studies.* Although related to
12 the Regional Resource Planning Study, the former is intended to
13 look at the supply and demand dynamics of the regional
14 wholesale market. In contrast, the purpose of wholesale market
15 studies is to produce a market price forecast. With the passage of
16 the 1992 National Energy Policy Act, utilities began to anticipate
17 and prepare for greater reliance on the wholesale power market.
18 Also anticipating this change in the industry, we improved our
19 ability to forecast forward prices throughout the region with more
20 sophisticated modeling tools. With this kind of market price
21 analysis, we can derive forecasts of the availability and cost of
22 wholesale market supplies throughout the West. This analytical
23 tool improved the accuracy of our discounted cash flow studies
24 used for our "buy vs. build" scenarios, both project-specific and
25 generic.
26

- 1 • *Busbar Cost Determinations.* For every significant potential
2 long-term purchase or new generation construction project, we
3 analyzed the potential incremental and total effect on APS
4 customer prices by preparing a comprehensive revenue
5 requirement or busbar cost analysis. In doing so, we looked at the
6 cost of power from the new project and integrated that with the
7 existing generation portfolio to determine the new average price
8 for the entire new generation portfolio. A busbar cost analysis
9 determines the cost of power at the generation bus, including
10 capital costs. A traditional busbar cost analysis forms the basis for
11 determining the revenue required to pay for the capital and
12 operating costs of utility assets at an assumed rate of return on
13 equity and capital structure. We performed the test to ensure APS
14 generation was competitively positioned and the impact on APS
15 customer prices was quantified.
- 16 • *Long-range fuel and purchased power cost forecasts.* These
17 studies form the basis for a number of corporate operational and
18 financial planning decisions. We typically incorporate forecasts
19 by outside groups as to fuel prices, power plant capacity factors,
20 or financial information and adapt their data to our specific
21 situation. We may also reformat that data so that it can be used in
22 the existing APS corporate software models. In addition to
23 providing quantitative input for these models, we can use the
24 forecasts in sensitivity analyses to determine price and supply risk
25 profiles for different resource alternatives. Fuel and purchased
26

1 power forecasts also form a baseline from which "buy vs. build"
2 and other resource planning analyses emerge.

3
4 **Q. WHAT DID YOU DO WITH ALL THESE STUDIES?**

5 A. The results from these various technical analyses were then integrated,
6 summarized, and presented to top APS management for review. These
7 presentations offered actionable alternatives for decision-making by APS officers
8 or Board members, or both. As I will demonstrate in the balance of my testimony,
9 we not only planned these units to meet APS customer growth, but these assets
10 were also found to be of significant long-term economic value to our customers.
11 Our resource planning decisions were based on a thorough understanding of the
12 Western markets, an essential ingredient for planning of new generation assets in a
13 more competitive market environment. Every step of the way from the inception of
14 the project to a next decision point and/or change in the critical assumptions used
15 to arrive at the previous decision, we re-evaluated the economic viability in support
16 of continuation of the project(s). When continued economic support for the projects
17 was not justified, further commitments were stopped or altered.

18 **Q. DO SOME OR ALL OF THESE RESOURCE PLANNING ANALYSES**
19 **REQUIRE WHOLESale MARKET DATA TO BE GATHERED OR**
20 **ESTIMATED?**

21 A. Yes. Not only must we look at what is available or likely to be available in the
22 market, we have to incorporate estimates of unit operating characteristics, fuel
23 prices and availability, and wholesale power prices, among other factors. Under
24 traditional regulation, much of this data was filed with various regulatory agencies
25 and generally available. With the advent of wholesale competition on a wide scale,
26 the cost data underpinning the market has become much less transparent.

1 Q. CAN YOU DESCRIBE THE VARIOUS METHODS OF GATHERING
2 MARKET INTELLIGENCE AND PRICE DISCOVERY USED IN THE
3 ABSENCE OF A TRANSPARENT WHOLESALE POWER MARKET?

4 A. Yes. We tested the wholesale market in a variety of ways. In addition to issuing a
5 formal request for proposal ("RFP") in 1995, which will be discussed later in my
6 testimony, we used four additional methods. First, valuable market data was
7 obtained through the conduct of the Company's day-to-day business, which
8 obviously includes sales and purchases from the wholesale electric market.
9 Second, APS (and later PWEC) explored and discussed partnering with other
10 market participants such as Reliant, U.S. Generating and Calpine, which allowed
11 us insights into their view of the then current and future wholesale market. Third,
12 APS simulated through computer modeling the WECC regional and sub-regional
13 (Arizona/New Mexico) energy and capacity markets. Finally, APS performed
14 internal financial and economic evaluations of both available generation
15 technologies and known purchased power options in the West.

16 Q. WOULD YOU EXPLAIN EACH OF THESE FOUR METHODS OF
17 ASSESSING THE WHOLESALE MARKET?

18 A. By conducting business daily in the wholesale market, we contacted suppliers
19 routinely to determine whether they had power available and the price they were
20 asking. As electricity markets moved toward restructuring and wholesale trading
21 activity increased, electricity products were standardized for electronic commodity
22 trading. At least at first, price information became more readily available. This
23 was a very valuable source of information, especially from the late 1990s through
24 2001. However, since the California market failure, trading at various market hubs
25 has become very "thin," especially for more than a year or two out, and some
26 markets have either collapsed altogether (California Power Exchange) or stopped
trading electricity until very recently (New York Mercantile Exchange). Thus,

1 today's published market data is suspect at times and should be extrapolated with
2 regard to larger volumes and more remote delivery dates only with extreme
3 caution.

4 By forming partnerships or co-tenancies with other companies, historically APS
5 has sought to improve its overall generation system efficiency and simultaneously
6 reduce the risk exposure of APS customers. Examples include the joint ownership
7 of the Palo Verde, Four Corners, Navajo and Cholla power plants. In recent years,
8 we have had numerous discussions with utilities and merchant generators in an
9 effort to find the best combination of generation assets for our customers and to
10 spread the risk of large power station projects. These discussions helped us to
11 periodically "take the pulse" of the market.

12
13 On a regular basis, we simulated the regional and sub-regional energy and capacity
14 markets for the WECC using regional software planning tools such as the General
15 Electric Multi-Area Production Simulation Program ("MAPS"). This program,
16 which we have modified considerably to model our specific situation here in the
17 Southwest, allows us to simulate a "dispatch" of the entire WECC generation and
18 transmission system. In this manner, APS could test various expansions or
19 contractions of resource scenarios for their impact on marginal generation costs,
20 which in turn set market prices. With this sophisticated simulation, we identified
21 various regional and sub-regional generation capacity deficits or surpluses,
22 pinpointed the existence and impact of load pockets in transmission-constrained
23 areas, identified other areas where additional capacity will be needed to serve
24 customers and specified cost-effective locations for building new generation
25 capacity. As I explain later in my testimony, finding a potentially cost-effective
26

1 location, which must consider both the busbar cost of the generator and its access
2 to off-system markets, reduces customer costs.

3 Finally, and perhaps most importantly, the information gathered from the above
4 regional market studies allowed us to perform our own economic and financial
5 evaluations of the available alternatives for meeting customer demand. Our
6 evaluations enabled us to choose the best option (best, that is, from the combined
7 point of view of cost, reliability, and risk) from the available alternatives—either
8 buying or build alternatives—that result in the most customer-beneficial projects.
9 The Company relies on a variety of methods in preparing the energy and peak
10 demand forecasts. These methods include end use analysis, econometric model
11 development, expert opinion, customer contact, and trend analysis related to retail
12 and native load wholesale customer demand in the Company's service territory.
13 The methods used to produce the load forecast are consistent with methods that are
14 used across the industry and are similar to the methods that were documented in
15 each of the Company's past Integrated Resource Planning ("IRP") practices and
16 filings (in 1992 and 1995) to this Commission.

17
18 **Q. DOES THE RESOURCE PLANNING PROCESS DEPEND UPON LONG-TERM FORECASTS OF APS LOAD REQUIREMENTS?**

19 A. Yes.

20
21 **Q. PLEASE DISCUSS THE APS LOAD FORECASTING PROCESS.**

22 A. The load forecast prepared at APS for its Arizona customers includes total APS
23 service territory expected retail load plus demand from cost-of-service based
24 wholesale contracts. The full requirement wholesale contracts in the past had
25 amounted to over 300 MW of load. Today they contribute only about 7-8 MW of
26 coincident peak demand in the forecast.

1 About 90% of APS energy sales are made to "mass market" residential and small
2 to medium business customers, with the remaining 10% to large business
3 customers. This latter group has discrete load requirements and growth trends, and
4 thus, forecasts of energy sales to these customers are made with specific input from
5 them on their expected operating plans. The residential energy forecast is derived
6 from both econometric and end-use studies. The small to medium commercial sales
7 forecast is derived from an econometric model using independent factors such as
8 job growth, office and retail floor space additions, the price of electricity and
9 weather effects.

10 The peak demand forecast is then determined by applying class-specific load
11 factors to the projected customer class sales forecasts and adding line losses.
12 Historical information on class load factors results from a reconciliation of each
13 year's system peak with the results from a randomly drawn statistical sample of
14 retail customers. Changes in the seasonality of the retail sales forecast are
15 controlled by calculating the historical load factors with summer period sales only,
16 and extrapolating the trend in the load factors through the forecast horizon.

17
18 Both energy and peak load forecasts of APS service territory include transmission
19 and distribution system losses. System loss rates coincident with the system peak
20 are based on historical observation on the EHV system and engineering estimates
21 of distribution level losses. These system loss rates are also trended into the future
22 to develop the forecast.

23 Historically, APS has reviewed its customer load forecasting data and associated
24 assumptions twice a year. A short-term (normally up to 5 years) customer peak and
25 energy forecast is carefully reviewed in the fall upon good knowledge of the most
26

1 recent system summer conditions. The longer-term (up to 20 years) load forecast is
2 established in the spring and also becomes a basis for generation planning, fuel
3 forecasting and financial forecasting.

4 APS' current forecast expects energy sales to grow at an average annual rate of
5 4.3%, with higher growth rates occurring in the near term as the economy and
6 associated electricity demand recovers from the downturn in economic activity.
7 This compares with the most recent 5-year average growth rate from 1997 to 2002,
8 on a weather-normalized basis, of 3.4% and the corresponding 10-year average
9 growth rate of 3.4%. Demand growth is estimated at 4.2% per year, which is
10 actually slightly less than our actual experience over the 10-year period.
11

12 **Q. WERE THE APS LOAD FORECASTING PROCESS AND RESULTS**
13 **ACHIEVED FROM THE PROCESS YOU HAVE DESCRIBED ABOVE**
14 **CONSISTENT WITH INDUSTRY PRACTICES?**

15 A. Yes. Although the APS load forecasting process has continuously been improving,
16 it has always used state-of-the-art industry standard software, computer tools and
17 practices. Historically at APS, the load-forecasting group was comprised of a
18 management team from many disciplines within the Company. It also coordinated
19 its efforts with the industry (WECC) and neighboring systems, although this is
20 increasingly difficult in today's competitive business environment.

21 **Q. HOW WERE THESE RESULTS INCORPORATED IN YOUR RESOURCE**
22 **PLANNING?**

23 A. These results, along with APS' customer electricity use patterns and customer peak
24 load and energy demand forecast, allowed us to prepare APS system specific
25 resource planning studies. We periodically reviewed APS' customer supply and
26 demand balance and identified capacity and energy shortfalls. We prepared annual
and sometimes more frequent L & R plans for APS load balance. Many of these

1 plans have been previously provided to the Commission or its Staff. The L & R
2 studies are the basis for APS daily system operation, construction budgets, fuel
3 planning, and the Company's overall financial forecast.

4 *B. Planning History- Past and Recent Impacts*

5 **Q. HAS APS EXPERIENCED GENERATION PLANNING CYCLES OVER**
6 **THE YEARS?**

7 A. During the last thirty years with APS, I have seen several cycles of generation
8 construction programs. Each was necessarily built upon existing resources while
9 incorporating the Company's views concerning future events. Going back to the
10 early 1950s, APS served its customers' needs primarily with oil and gas-fired
11 plants. Our customer load was relatively flat and did not exhibit the high summer
12 peak demand we have since experienced. By the 1960s and early 70s, the strong
13 growth within our service area coupled with technological advances and better
14 economic conditions allowed more customers to afford refrigerated air-
15 conditioning and pools. APS' customer demand grew at an annual rate of over 7%.
16 To complement our historic base of gas and oil-fired generation, we built or
17 acquired ownership interests in large coal plants such as Four Corners, Cholla and
18 Navajo. They diversified the Company's fuel mix and served our growing service
19 area efficiently with low-cost base-load capacity.

20 In the 1970s, APS continued to grow rapidly. The Company found itself in need of
21 peaking capacity, and APS added quick-start gas turbine units at our existing plant
22 sites in Tempe, Phoenix and Yuma. Population growth in the Valley and in
23 Arizona during the 1970s and 1980s continued to increase customer demand,
24 which was now growing at the staggering average rate of 8.5% per year in our
25 service territory. By 1978, natural gas could not legally be burned as a boiler fuel
26 for electricity production from new units, and additional coal was a difficult

1 resource option due to increasing environmental constraints. APS' increased
2 customer needs were met with nuclear energy by constructing a jointly-owned
3 large power project at Palo Verde. And of course, as our customer demand called
4 for additional generation supplies, at the beginning of this century we built
5 generation at Redhawk, West Phoenix and Saguaro to assure the future reliability
6 of APS service.

7
8 **Q. WHAT HAVE WE LEARNED FROM THESE PAST GENERATION CONSTRUCTION CYCLES?**

9 A. When APS moved from a utility dependent almost entirely on small oil and gas
10 generating units to adding the large coal units at Cholla, Four Corners, and Navajo
11 during the 1960s and 1970s, it created upward pressure on prices in the near term.
12 But coal protected our customers from the full effects of the oil and gas price
13 shocks and shortages of the time. Similarly, the construction of Palo Verde in the
14 1980s severely stressed the Company's financial condition and led to several rate
15 increases. And yet, it was the efficiency of these units that allowed for the more
16 than decade-long rate stability and even rate decreases that have marked the
17 Company's experience in the 1990s and into this century.

18
19 **Q. WHAT DOES THE SUPPLY-DEMAND BALANCE IN THE LATE 1980S AND EARLY 1990S ILLUSTRATE ABOUT THE CONCEPT OF "LUMPINESS" IN GENERATION AND TRANSMISSION CAPACITY?**

20 A. As we emerged from the 1980s and into the early 1990s, the entire WECC and our
21 sub-region had more than enough generating capacity. APS itself had sufficient
22 capacity, primarily because of the addition of the nuclear units at Palo Verde. The
23 cost efficiencies of nuclear power required APS to add large increments of this new
24 capacity, and thus it was anticipated that APS would have more than adequate
25 capacity for at least several years.
26

1 This process of adding large amounts of capacity with the completion of a new
2 project – common in the planning process for both generation and transmission
3 assets – is often referred to as “lumpiness.” The capacity added is necessarily
4 larger than the immediate need, but the lumpiness gets “smoothed out” and the cost
5 efficiencies begin to appear as load grows and the resource becomes progressively
6 more fully and more frequently utilized. In fact, it is almost impossible to gain the
7 long-term cost efficiencies of large facilities without experiencing some initial
8 “lumpiness.”

9
10 **Q. IS “LUMPINESS” ONLY ASSOCIATED WITH THE PHYSICAL**
11 **ATTRIBUTES OF NEW GENERATION SUCH AS NET CAPACITY OR**
12 **CAPACITY FACTOR?**

13 A. No. The capital costs of new generation are also proportionately greater than that of
14 older, more-depreciated generation. That is the primary reason why the inclusion of
15 the PWEC generation in the Company’s rate base causes an increase in overall
16 revenue requirements. This is not at all unusual, as can be seen by my earlier
17 discussion of the impact of adding coal and nuclear generation during past
18 generation construction cycles.

19 **Q. HOW DID THE MORE RECENT RESOURCE PLANNING HISTORY AT**
20 **APS AND PWEC LEAD TO THE EVENTUAL DECISION TO**
21 **CONSTRUCT NEW GENERATION?**

22 A. A year-by-year review of our APS resource planning activities demonstrates the
23 extraordinary volatility of the last eight years and our flexibility and agility in
24 responding to unprecedented changes in regulation and the marketplace. This
25 review also illustrates that we were carefully monitoring the APS capacity deficit
26 in the context of a then capacity surplus in the WECC as a whole. In this regard,
1995 was the appropriate place to start because all the relevant planning studies for
our decision to construct the PWEC assets began with the 1995 Integrated

1 Resource Plan ("IRP") filing. This IRP was filed with the Commission under the
2 provisions of the Commission's IRP regulations. Equally important was the 1995
3 RFP to which I have previously referred in my testimony. At that time, we were
4 making and planned to continue to make relatively modest purchases in the
5 competitive wholesale market in addition to our long-term contracts. There did not
6 appear to be a significant reliability need for several years.

7 **Q. PLEASE DISCUSS THE 1995 RFP AND ITS SIGNIFICANCE IN**
8 **SUBSEQUENT RESOURCE PLANNING DECISIONS.**

9 A. In conjunction with the 1995 IRP, which was filed in late December of that year
10 with the Commission, the Company issued an RFP. APS then had the option to
11 convert its existing purchases from PacifiCorp (obtained in the early 1990s as part
12 of the Cholla Unit 4 sale, which, along with the PacifiCorp contract itself, was
13 approved by the Commission) to a full seasonal exchange beginning in 1996. To
14 test the economics of that option, APS issued an RFP to some 34 entities having
15 some presence, either current or announced, in the WECC. From that RFP, we
16 received seven responses.

17 None of the proposals could match the economics of the PacifiCorp seasonal
18 exchange, and thus APS elected that option. However, the responses were
19 nonetheless very informative. Virtually no responding party wished to enter into
20 the 10-20 year agreement APS was soliciting, and those that did would do so only
21 by constructing a new plant in the Southwest with the APS contract supporting its
22 construction. This indicated to APS that the regional surplus of capacity was not
23 likely to extend significantly longer than would the Company's own period of
24 having sufficient capacity. Moreover, APS should not expect to obtain long-term
25
26

1 purchased power agreements at costs less than the cost of constructing its own new
2 plants and quite likely higher.

3 Another interesting fact, the significance of which can best be appreciated in
4 hindsight, was that the two highest-rated entities responding to our RFP from the
5 standpoint of creditworthiness and financial stability were Enron and U.S.
6 Generating, both of which are now bankrupt less than eight years later. If we had
7 signed a 10-20 year agreement with either of these entities on favorable terms, it is
8 likely we would be in the same position as Connecticut Power & Light, which is
9 facing termination of its favorable agreement with NRG by a Bankruptcy Court.
10

11 **Q. WHAT TOOK PLACE IN THE YEARS IMMEDIATELY FOLLOWING**
12 **1995?**

13 A. In 1996 and 1997, we continued to refine our models and review our resource
14 needs as we monitored the development of competition in California as well as
15 Arizona. In 1996, MAPS became a major tool for our planning analyses,
16 significantly advancing our ability to model regional supply and demand and to
17 forecast locational prices. MAPS also accounted for and anticipated transmission
18 congestion issues.

19 Also in 1996, California passed its restructuring legislation, AB 1890. AB 1890
20 froze customer rates after a 10-percent reduction, implemented retail competition
21 immediately and established a California Independent System Operator ("CAISO")
22 to operate the transmission system. AB 1890 also set up a California Power
23 Exchange ("CPX") to operate a short-term wholesale power market based on a
24 pooling of resources (i.e., all generation is sold into a single "pool" from which
25 load serving entities also purchase their needs, usually through day-ahead
26 transactions). APS simulated the operation of the California "Poolco" market,

1 attempting to determine its effect on wholesale prices in the WECC and any
2 unintended consequences for APS wholesale and retail prices. These analyses
3 demonstrated the risk to APS and its customers from divestiture and became the
4 basis of the Company's position on that issue.

5 In 1997, APS also began to see signs that customer demand in the Valley and
6 Arizona as a whole was growing faster than had been previously forecast. The load
7 forecast for 2003 grew from 4413 MW (in the 1995 IRP) to 4774 MW in the 1996
8 long-range forecast. It then increased to 4980 MW in the 1997 forecast. This
9 represented a nearly 13% increase in just two years.

10 Also in 1997, APS carried out the kinds of generation planning activities described
11 earlier – evaluating generation needs, providing fuel and purchased power budgets
12 and forecasts, and carrying out regional simulations including the effects of
13 California restructuring. APS made a technology assessment to determine the most
14 economical generation technology for APS load. Anticipating the potential coming
15 of restructuring in Arizona, APS developed a discounted cash flow financial model
16 to calculate IRR as a supplement to the traditional revenue requirement and busbar
17 cost analyses. The most immediate issue that these new planning tools had to
18 address was the potential for acquiring additional shares of plants APS was already
19 operating or at least had an existing ownership interest.

20 At this time, the California utilities were planning to sell most of their generation
21 assets. As joint owner of some generating units with Southern California Edison
22 Company ("SCE"), we examined the economic feasibility of acquiring SCE's share
23 of Palo Verde and Four Corners. Because El Paso Electric Company ("El Paso")
24 also had often expressed an interest in selling its share of Palo Verde, we evaluated
25
26

1 the value of that share of these projects as well. These units were well placed both
2 to serve APS customers and to access regional markets for off-system sales
3 margins. They also had proven track records of performance and would not need
4 new siting authority or land acquisition.

5
6 **Q. WHAT HAPPENED NEXT?**

7 A. Toward the end of 1997, APS had conducted a number of market assessments that
8 were incorporated in our long-range forecast in early 1998. The purpose of these
9 market assessments were to determine whether APS customers could expect any
10 reduction in costs if the Company purchased large amounts of power from the
11 competitive market instead of acquiring or building additional generation.

12 In this analysis, the Company assumed a fully functional and effective CPX and
13 CAISO. Another conservative assumption was made in the study to avoid later
14 allegations that the analysis might be biased in favor of constructing new
15 generation. Specifically, it was assumed that APS' construction cost for new gas-
16 fired projects would be 10 to 20% higher than the cost to merchant generators. This
17 was largely due to the belief that a merchant generation project would be generally
18 project-financed, thus allowing higher leverage, and we also speculated that the
19 merchant generators might initially accept a lower initial return on equity in an
20 attempt to achieve or increase their market share.

21 Using these cost assumptions, we compared two basic scenarios – one in which we
22 began a construction program in 2001 to met APS' customer needs and a second in
23 which we relied on the wholesale market. Note that APS had already decided that
24 any new capacity would have to begin somewhat earlier than before in view of the
25 higher customer growth. The results of this analysis slightly favored relying on the
26

1 competitive market over new construction. However, our analyses (which I will
2 return to later) always supported buying additional shares of our existing jointly
3 owned generating assets, such as Palo Verde, Four Corners or Navajo. As a result
4 of this study, and for planning purposes, APS increased its anticipated reliance on
5 the competitive market to as much as 1000 MW through 2004. APS continued to
6 believe that no major new construction was required until 2004.

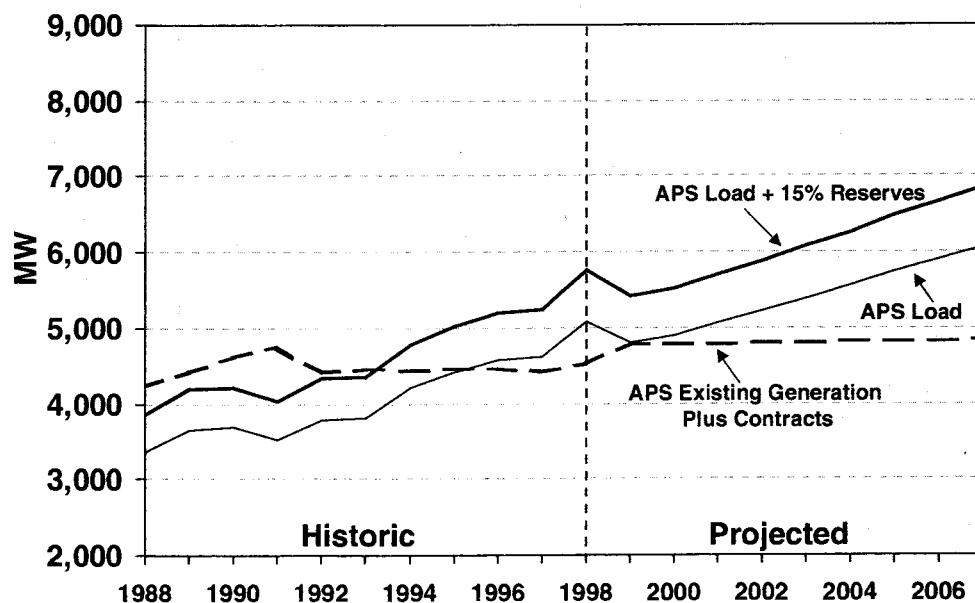
7 This relative calm was to end quickly. The summer of 1998 saw a soaring actual
8 peak demand, which exceeded 5000 MW for the first time. This 1998 peak was in
9 excess of the 1997 forecast for 2003, and thus represented an increase in load
10 growth of some five years in a little over one year. SRP was experiencing similar
11 unanticipated load growth, and Nevada also was growing rapidly. Percentage-wise,
12 California was growing at a slower pace, but with its incredible size compared with
13 other western states, it was gobbling up capacity at an alarming rate. APS needed
14 to revise its plan from the 1995-1997 period in light of this new data.

15
16 Planning activities once again thoroughly reviewed the Western generation markets
17 and continued with the assessment of the potential for purchasing jointly owned
18 existing units that we operated. We also analyzed the potential of various new
19 generation sites around the WECC through our regional planning model and
20 determined that Arizona was not as attractive a market to merchant generators as
21 California and Nevada. By October of 1998, APS had reviewed the regional
22 situation – both neighboring utilities and the WECC as a whole – and concluded
23 that the Southwest was becoming unacceptably short of capacity and dependent on
24 imports. Both of these latter findings were very significant to the “buy vs. build”
25 decision rapidly being forced upon the Company. If this shortfall continued, and if
26 Arizona had to compete with California for new generation, APS and its customers

1 would be exposed to very significant and, in our judgment, unacceptable risks of
2 higher purchased power costs. System reliability was also in danger of being
3 compromised, especially considering that no economic analysis performed by APS
4 showed that the most profitable location for a merchant plant would be within
5 metro-Phoenix. Figure 4 illustrates the increasing gap between APS-owned
6 generation and APS load that we saw developing in future years by mid-1998.

7 **FIGURE 4**

8 **APS New Generation Requirement**
9 **Load Forecast - 1998 LRF**



21

22 At this point, we began studies to identify a new generation site or sites capable of

23 accommodating 1500 to 2000 megawatts. The official recognition in an APS

24 planning document of what was the project called "Hedgehog" (later renamed as

25 Redhawk) appeared as part of our Generation Growth Plan in January 1999.

26

1 **Q. WHAT DID YOUR 1999 LONG-RANGE FORECAST INDICATE ABOUT**
2 **APS GENERATION NEEDS AT THE TIME THE DECISION WAS MADE**
3 **TO BUILD THE PWEC UNITS?**

4 A. At the time when the current version of the Electric Competition Rules was being
5 considered by the Commission in 1999, the generation deficit at APS was growing
6 to an alarming level and was projected to approach nearly 2200 MW by 2007. Our
7 projections also showed other utilities in the Desert Southwest were becoming
8 increasingly short of generation capacity and no, or very little, apparent merchant
9 activity in the region. And our analyses of the western generation and transmission
10 system were increasingly revealing overloads of the transmission grids and
11 significant generation import issues within major load centers like Phoenix.

12 But while increasing demand was the dominant factor affecting our planning
13 decisions, it was by no means the only influence. The effect of restructuring the
14 electric industry in California and other nearby states as well as Arizona had to be
15 factored into our decisions. In Arizona, specifically, we had to consider the
16 possible effect of divesting our generation assets to one or more companies. APS
17 maintained forcefully before this Commission that it, or at least an affiliate, needed
18 to retain control of our existing and any future generation assets to avoid exposure
19 to the risks of a totally fragmented, potentially dysfunctional and, if not
20 unregulated, certainly under-regulated, wholesale market.

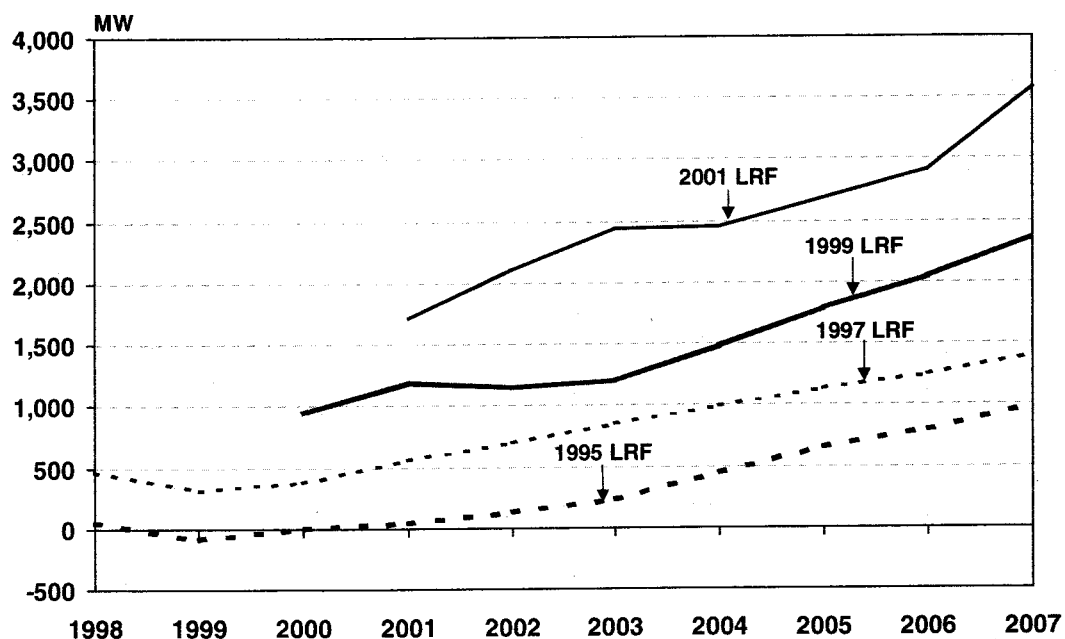
21 **Q. COULD YOU SPECIFICALLY ADDRESS THE ESCALATING LOAD**
22 **GROWTH SITUATION FACED BY APS?**

23 A. APS experienced a strong acceleration of load growth within its control area that
24 had a dramatic impact on projections of the Company's future resource needs. A
25 pictorial representation of APS' changing annual load forecast (including 15%
26

1 reserves) between 1995 and 2001 and corresponding additional new generation
2 requirement for the projected year 2003 is shown below in Figure 5.

3 **FIGURE 5**

4
5 **APS New Resource Requirements**
6 **Forecast**



18 **Q. WHAT PLANNING STUDIES WERE PERFORMED BY APS IN 1998-99**
19 **TO ASSURE THAT THERE WOULD BE AN ADEQUATE GENERATION**
20 **SUPPLY FOR THE EXPECTED HIGH LOAD GROWTH IN THE**
21 **COMPANY'S SERVICE TERRITORY?**

22 **A.** In anticipation of high load growth within the APS service territory, a series of
23 regional generation planning studies, beginning both prior to and extending after
24 the summer of 1998, became part of the strategic planning for the new reliability
25 generation construction program at APS. The economics of building new
26 generation in Arizona vs. elsewhere in the WECC, the depressed electric wholesale
market prices and the increasingly negative regional supply situation, both of

1 neighboring utilities and the WECC as a whole, were all analyzed. We concluded
2 that along with Arizona, the Southwest was also becoming unacceptably short of
3 generating capacity and increasingly dependent on imports beyond the
4 transmission system's capabilities. Our market intelligence research group found
5 that all the independent power producers' known generation activities were
6 elsewhere in the United States and especially in California. There was no or very
7 little activity in Arizona. APS system reliability became our paramount concern.
8 Thus, our new generation program was initiated in late 1998.

9
10 **Q. WERE OTHER NON-BUILD OPTIONS CONSIDERED TO ENSURE
ADEQUATE GENERATION SUPPLY FOR APS INCREASED GROWTH?**

11 **A.** Yes. We undertook a comprehensive review of market alternatives, including all
12 existing and jointly-owned assets potentially available for sale in the Southwest
13 and potential new generation construction sites in Arizona and elsewhere in the
14 WECC. Among all the jointly-owned assets options identified, SCE's share of Palo
15 Verde and Four Corners, TEP's share of Navajo and Four Corners, and El Paso's
16 share of Four Corners and Palo Verde were seriously considered. In Attachment
17 AB-4, I show an example of our economic historical analyses of the busbar cost of
18 these possible acquisitions. It is compared both with the assets PWEC expected to
19 receive from APS and the planned Redhawk and West Phoenix projects. The
20 subsequent acquisition of these interests in the existing Palo Verde, Four Corners
21 and Navajo plants was negotiated with varying degrees of initial success. However,
22 for various reasons, all of these efforts eventually failed.

23
24 **Q. WHAT DID YOUR LONG-RANGE FORECAST INDICATE ABOUT THE
RESOURCES NEEDED FOR ARIZONA AND THE DESERT
SOUTHWEST?**

1 A. Our long-range forecasts showed that Arizona and the Southwest needed to import
2 capacity during the peak summer months. For Arizona as a whole, our 1998
3 forecast predicted statewide total demand in 2003 of 12,897 MW and resources of
4 11,633 MW, a deficit of 3199 MW even with a moderate 15% reserve margin. In
5 the Desert Southwest, we forecasted in year 2003 total demand of 20,701 MW and
6 resources of 17,848 MW, a deficit of 5958 MW.

7 For these and other reasons, we became concerned about APS system reliability.
8 There was considerable doubt as to whether the transmission system would be able
9 to import enough capacity into the Southwest and Arizona at times of peak
10 demand, even if capacity were available at a reasonable cost from other states or
11 regions. After all, the load elsewhere in Arizona and also in Southern Nevada was
12 growing at least as fast as APS load. In addition to these concerns, we were unsure
13 about the effect the new California market structure would have on the Western
14 wholesale market. Because California is such a huge market in comparison with
15 Arizona and the rest of the western states, even on a cumulative basis, we knew the
16 impact of that California market on the Southwest would be both significant and
17 difficult to predict.

18
19 **Q. AT THE TIME YOU DECIDED TO BUILD THE WEST PHOENIX AND**
20 **REDHAWK UNITS, WAS MERCHANT CAPACITY AVAILABLE IN**
21 **ARIZONA TO MEET THE NEEDS OF APS CUSTOMERS?**

22 A. No. At the time we made the corporate commitment in late 1998 to build the West
23 Phoenix and Redhawk units, the rapid increase in potential Arizona merchant plant
24 activity was still in the future. By the spring of 1999, when West Phoenix was
25 officially announced, there were still only three merchant plants announced or
26 under construction in Arizona. These were the South Point, Griffith, and Desert
Basin facilities. All three of these plants were announced in late 1998. The

1 locations of South Point and Griffith in the far northwest corner of Arizona, outside
2 our service area and transmission system, indicated that those plants were targeting
3 California and Nevada markets. Desert Basin was eventually to be committed to
4 SRP. Moreover, none of these plants would be of any use in serving load within the
5 constrained metro-Phoenix area during peak, which was becoming an increasing
6 reliability concern to APS in the late 1990s.

7 Even by the time the formal public announcement was made concerning Redhawk
8 in September 1999, only two additional new plants had been announced. And those
9 announcements had been made only a mere couple of weeks earlier. These new
10 plants were SRP's 225 MW Kyrene facility and Sempra's 1000 MW Mesquite
11 plant.

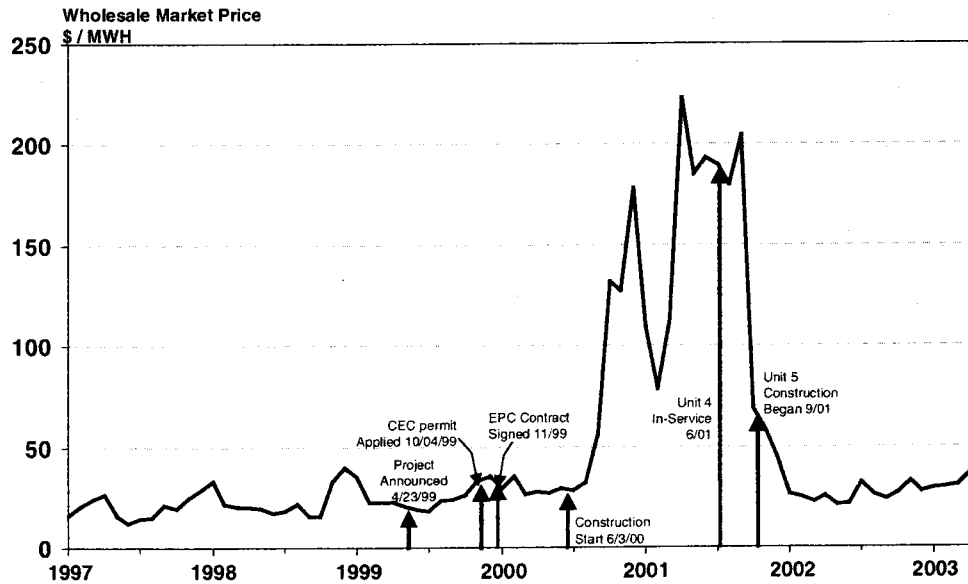
12
13 Kyrene was neither a merchant plant nor one likely to solve the Company's long-
14 term resource needs. SRP was constructing this relatively small plant to serve its
15 own retail load and showed no interest in either partnering on the project or having
16 APS acquire any of Kyrene's output. Moreover, SRP did not bid either of its new
17 generating facilities (Kyrene and Santan) in the recent APS Track B solicitation.
18 Sempra contracted the Mesquite plant to California, as expected, and also did not
19 participate in the recent APS Track B solicitation process.

20
21 **Q. DID PWEC BUILD ITS ARIZONA POWER PLANTS IN HOPES OF**
22 **EXPLOITING THE CALIFORNIA MARKET PROBLEMS?**

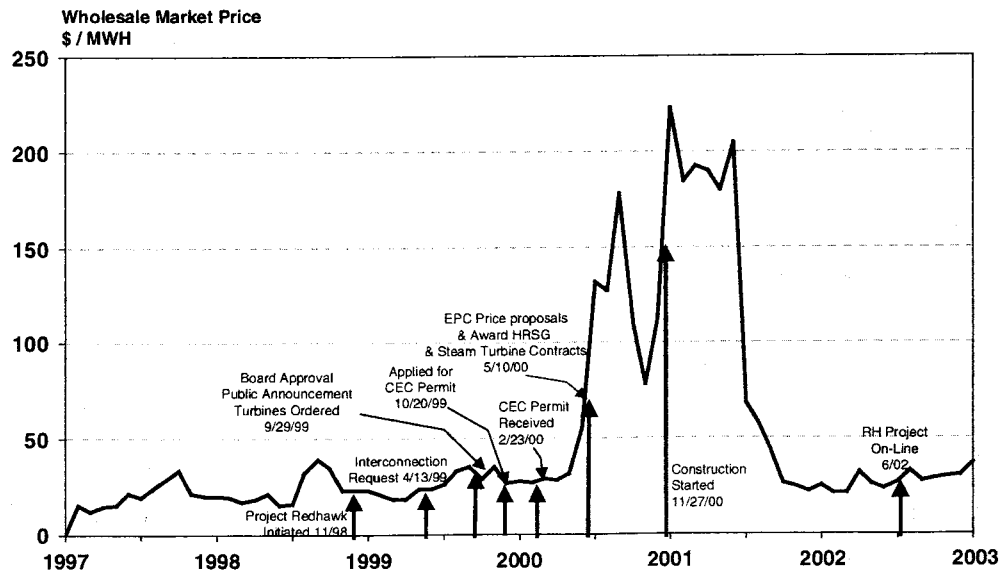
23 A. The goal was serving APS, not California. Although off-system sales are an
24 important part of all power plant economics, PWEC announced and began
25 implementation of its plans for the West Phoenix and Redhawk power plants
26 before the rapid increase in Western power prices. This timing is shown
graphically for both West Phoenix and Redhawk in Figures 6 and 7, below.

FIGURES 6 AND 7

West Phoenix Project Major Events



Redhawk Project Major Events



1 But during the California-induced power crisis of 2000-01, a number of new
2 merchant plants were begun in Arizona. Those plants clearly were intended to
3 capitalize on the run-up in prices, and this intention has been confirmed by the
4 subsequent cancellation of some of these plants as power prices fell.

5 This contrast in timing is no coincidence. PWEC's construction plans were driven
6 by the need to supply APS customers with reliable power. And the timing was
7 none too soon for APS. By the time construction of West Phoenix and Redhawk
8 began in June and November 2000, respectively, the Western power crisis had
9 begun and keeping the lights on in Arizona without bankrupting the Company or
10 the state was clearly going to be a challenge.

11
12 **Q. HOW DID THE REGIONAL AND WESTERN TRANSMISSION**
13 **SITUATION AFFECT YOUR EVALUATION OF APS RESOURCE**
14 **NEEDS?**

15 **A.** While our earlier 1995-97 planning studies showed that the WECC had an excess
16 of capacity, we also recognized that the Western transmission system did not allow
17 interstate power transfers in sufficient amounts to accommodate increasing demand
18 growth in Arizona and the Southwest. There are constraints within the WECC
19 system outside APS' control that prevent the power from flowing into our area, and
20 within the APS system there are additional constraints, some of which I have
21 already discussed and others that exist due to the geography of our service area.

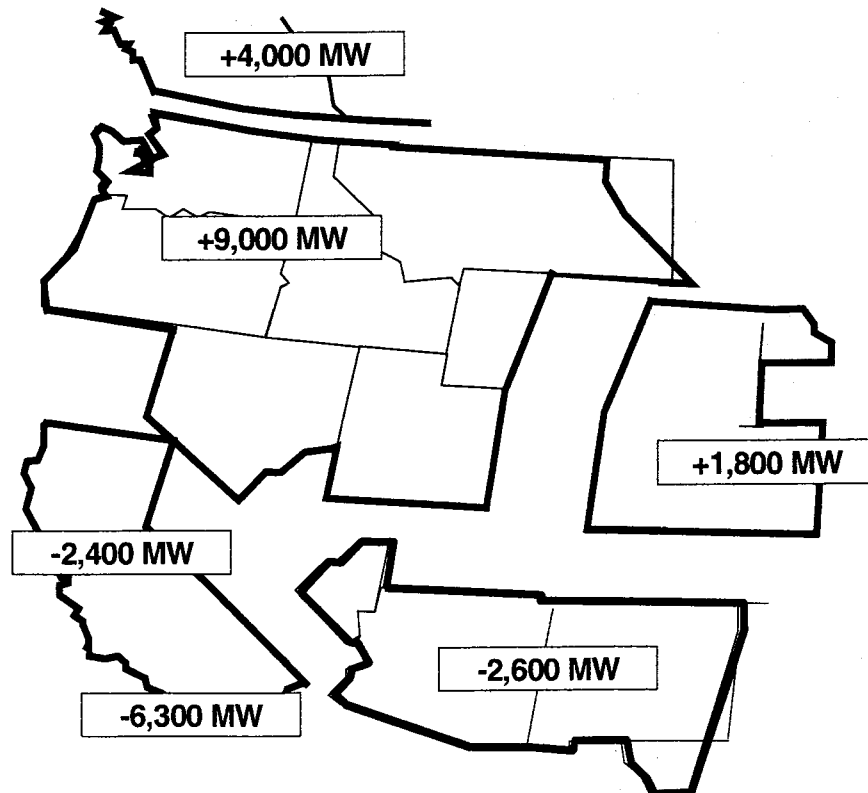
22 Further, we knew that increasing amounts of wholesale power exchange under
23 various competitive scenarios could put additional strain on the Western
24 transmission system, possibly in unpredictable ways. As noted by numerous studies
25 and articles on competition, the transmission networks in the U.S. were built
26 primarily by local utilities to provide power from remote utility-owned generation

1 to their service areas. They were not designed or constructed to serve as common
2 carriers for massive interstate exchanges of power between systems and regions in
3 furtherance of a national competitive wholesale market scheme.

4 In the West, the transmission transfer capabilities were likewise inadequate to
5 allow us to substantially increase our purchases from remote locations. As shown
6 in Figure 8, which came from a management presentation in 1999, the largest
7 available reserves were located in the Pacific Northwest, but the major
8 transmission links to and from that region go primarily to Northern California, not
9 to the Southwest.

10 **FIGURE 8**

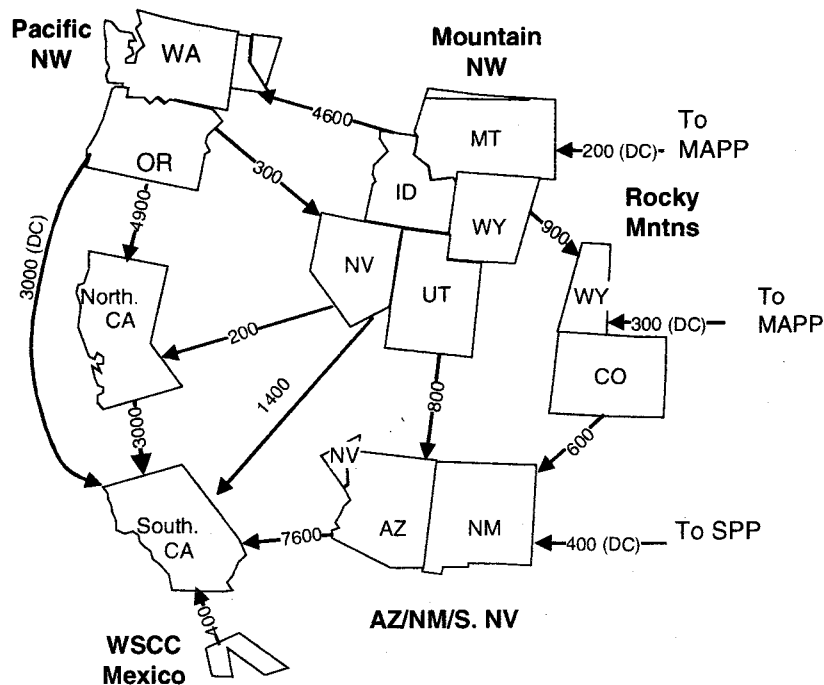
11 **Regional Generating Reserves -**
12 **Summer 2006**



1 This condition was unlikely to change because at the time, California also had a
2 significant capacity deficit. This would have encouraged an even stronger
3 transmission link with the Northwest, but made it even less probable that power
4 would flow from the Northwest through California to Arizona. There were and are
5 substantial transmission links between Southern California and Arizona, but
6 Southern California's capacity deficit (6300 MW) was well over twice that of the
7 entire Desert Southwest (2600 MW). Given the relative economic advantage of
8 transmitting power to California as compared to Arizona, it was doubtful that
9 significant Northwest power not already under contract to APS (such as the
10 PacifiCorp agreement) could be bid away by APS or any other Southwest utility.

11 The transmission pathway from Utah into Arizona allows for the transfer of up to
12 800 MW from the Northwest into Arizona, but this pathway also encounters a
13 constraint at the Four Corners substation, which limits the incremental import
14 potential to approximately 200 MW. In part, this is because the APS diversity
15 exchange of 480 MW with PacifiCorp uses the same transmission path to bring
16 power to our customers during the summer months. It is also because Four
17 Corners, and its related substation and transmission system, is owned by utilities in
18 Arizona, New Mexico, Texas and California. As I discussed earlier, the
19 transmission system in that area was primarily designed and sized to transfer power
20 from Four Corners to the Southwest and Southern California service territories of
21 the owner entities and not to wheel power from Utah through New Mexico into
22 Arizona. Figure 9, which was also originally prepared in 1999, shows the regional
23 transmission transfer limitations facing the Southwest in general and APS in
24 particular.
25
26

FIGURE 9
Western Power Markets Transfer Capability (MW)



Q. WHAT EFFECT DID THE CALIFORNIA DEBACLE HAVE ON RESOURCE PLANNING DURING THE YEAR 2000?

A. The year 2000 saw momentous events in the Western power markets—unprecedented high power prices and shortages, high natural gas prices and the complete failure of the wholesale market structure. These events had three primary effects on APS resource planning: elimination of the SCE purchase option due to legislation barring further divestiture of generation in California, acceleration of the reliability projects at West Phoenix, and a re-evaluation of projected WECC market prices and supply-demand balance.

1 In early 2000, PWEC received Certificates of Environmental Compatibility for our
2 West Phoenix and Redhawk facilities, respectively. Although we had considered
3 partnership arrangements for both of these projects – Calpine with West Phoenix
4 and Reliant with Redhawk, these plans had assumed that at least some of the
5 acquisition scenarios would pan out and did not fully consider the tremendous
6 explosion in customer demand we saw in 1999.

7 In 1999 and 2000, APS continued to experience customer growth at three times the
8 national average, as the expansion phase of the business cycle reached
9 unprecedented levels not seen in previous economic cycles post-World War II.
10 APS was forced to continuously revise its load forecasts upward to account for this
11 new phenomenon. Nor could this explosion in growth be viewed simply in
12 isolation, considering the supply problems and extreme price volatility being
13 experienced in California and other Western states. Thus, APS became increasingly
14 concerned about its ever-growing capacity deficit. We knew that an unusually hot
15 summer could put extreme pressure on reliability in the absence of the new PWEC
16 units. Moreover, APS' financial situation could become strained if the Company
17 were forced to buy power on the open market at exorbitant prices, thus threatening
18 the rate reductions under the 1999 Settlement.

19
20 APS was able to maintain Valley reliability in the summer of 2000 with the re-
21 commissioning of its old West Phoenix 4 and 6 units, but it was clear that more
22 dramatic measures would be needed for 2001 and beyond. Although by this time,
23 several other merchant generators had announced plans to build near Palo Verde,
24 their units would not be on line in time to meet our needs. Nor did we have any
25 assurance that these units would even be interested in Arizona given the lucrative
26 market in California. Therefore, and as a result of a study made in August of 2000,

1 PWEC advanced the planned in-service dates for the first two Redhawk units from
2 2003/2004 to 2002 and the last unit (Unit 4) from 2009 to 2005.

3 The acceleration of the construction schedule for Redhawk (so as to have the
4 capacity available for APS customers by 2002) carried with it some unintended
5 consequences. The energy from the plant would likely be more than could be used
6 solely to serve APS native load for at least the first couple of years. Thus, we
7 developed a plan to provide some capacity and energy to the wholesale market
8 during off-peak periods. This resulted in some opportunity costs to PWEC because
9 this off-system capacity and energy would be more valuable if construction could
10 have been delayed until the market shortage in the West was even more acute and
11 prices higher. But our study continued to show that a combined portfolio of
12 existing APS generation and new PWEC gas-fired plants produced lower costs
13 than relying exclusively on the wholesale market, whose structural flaws had
14 become glaringly obvious.

15
16 **Q. WHAT EFFECT DID THE AFTERMATH OF THE CALIFORNIA**
17 **DEBACLE HAVE ON YOUR PLANNING DURING 2001-2002?**

18 **A.** The California debacle and Western power crisis provided a direct – but not always
19 clear and certainly not preordained – path to this proceeding and our request to put
20 the PWEC Arizona assets into the APS rate base. The year 2001 began with
21 continuing high prices and California power emergencies, even during the winter
22 months when prices were expected to moderate. By early in the year, the California
23 utilities were nearly bankrupt, and the state, through the California Department of
24 Water Resources, took over the purchase of power for utility customers.

25 To assure reliable service during the summer of 2001, PWEC completed
26 construction of WP-4, while APS maintained the West Phoenix Steam Units 4 and

1 6, which had been re-commissioned the prior year, for another summer. PWEC
2 also brought in temporary, trailer-mounted generation at both West Phoenix and
3 Saguaro. We spent an estimated \$120 million to protect APS customers during this
4 extremely uncertain and volatile time in the power and natural gas markets. This
5 foresight paid off when on July 2, 2001, peak demand reached 5687 MW. We were
6 able to meet that demand, but even with WP-4 and PWEC's trailer-mounted
7 generation, APS was down to 36 MW of reserves in the Valley.

8 By operating existing units at the highest level and adding new capacity, some of it
9 on an emergency basis, we assured reliable service to customers and protected
10 them from skyrocketing market prices. These same high market prices bankrupted
11 one of the nation's largest utilities, put severe strains on many others, and led to
12 hefty rate increases for the customers of many Western utilities. In my opinion, our
13 response demonstrates the Company's commitment to its customers. These actions
14 also demonstrate our ability to remain agile enough to make short-term adjustments
15 within the context of a longer-term asset-based resource plan.

16
17 As we prepared to move the APS generation to PWEC, we knew that APS would
18 be required to buy all of its power on the wholesale market, with 50% through an
19 undefined auction or bidding process. Facing this prospect, given the dysfunctional
20 nature of the California and Western power markets, was daunting and extremely
21 risky for APS customers. As a result, we developed and filed with the Commission
22 in the fall of 2001 a plan to preserve an orderly progression toward competition and
23 for PWEC to guarantee APS customers a reliable supply of affordable power. APS
24 believed that the proposed long-term cost-based purchased power agreement with
25 PWEC, combined with mandatory open market purchases based on fixed formula,
26

1 would allow divestiture to proceed and for the wholesale market in Arizona to
2 develop over time, while still protecting APS customers.

3 During the latter half of 2001 the Western power markets collapsed. By the fall of
4 2001, the Enron scandal further eroded confidence in power markets and trading
5 activity. And by the beginning of 2002, the merchant power industry was already
6 beginning to falter. Although these events temporarily removed the threat of
7 skyrocketing power prices, they introduced the new issues of counter-party credit
8 risk, thinning markets, and the parade of project cancellations that will eventually
9 lead once again to capacity shortages later this decade. All of this reinforced the
10 Company's belief that having the existing APS assets as well as the new PWEC
11 assets available for APS customers in a single integrated package at reasonable
12 cost-of-service prices would be a better option. Under the terms of the Electric
13 Competition Rules and the 1999 Settlement, such unification of assets could only
14 take place within PWEC.

15
16 Although recognizing the same problems as APS, the Commission decided to
17 change course altogether and stopped the divestiture of APS generation in Decision
18 No. 65154 (September 10, 2002). This provided APS customers with a partial
19 market hedge similar to that envisioned by APS, but also resulted in the PWEC
20 gas-fired assets being stranded at PWEC.

21
22 **Q. COULD YOU SUMMARIZE THE REASONS WHY APS DECIDED TO**
23 **PURSUE AN ASSET-BACKED CONSTRUCTION PROGRAM TO**
24 **SATISFY ITS FUTURE NEEDS RATHER THAN RELYING**
25 **EXCLUSIVELY ON THE WHOLESALE MARKET OR BUYING**
26 **EXISTING CAPACITY?**

A. As I have previously discussed, APS looked at each of these options, both
individually and in combination, from 1995 through 2001. For construction

1 scenarios, all technologies' (gas / coal / nuclear) economics were evaluated on a
2 relative basis and sited at a generic location with varying unit sizes and
3 configuration. The risk of building gas-fired generation directly controlled by APS
4 or an affiliate of APS proved to be lower for both our customers and for APS than
5 the risk of not building and thus allowing APS customers to be exposed to an
6 unpredictable, uncontrollable, and unreliable wholesale market. This was because
7 the construction of modern gas-fired generation does not involve the sort of
8 construction-related risks one faced in the past when building coal or nuclear
9 generation. And with this gas-fired generation likely to be the market-setting
10 marginal resource, it was extremely unlikely that the wholesale market would
11 produce a lower long-run price than the cost of building one's own generation.

12 *C. Regulatory Background to APS Planning Decisions*

13 **Q. HOW DID REGULATORY ISSUES INFLUENCE THE PLANNING**
14 **PROCESS OVER THE LAST DECADE?**

15 **A.** This period was a time of considerable change and uncertainty in the economic and
16 regulatory arenas. Beginning in 1994 with the issuance of the California "Blue
17 Book"—essentially a manifesto for retail competition—it was evident that our
18 huge neighboring state, as well as the Federal Energy Regulatory Commission
19 ("FERC") would look for ways to promote competitive elements in the electric
20 utility industry.

21 **Q. WHAT WERE THE MAJOR REGULATORY ISSUES IN ARIZONA AT**
22 **THIS TIME?**

23 **A.** There was a widespread belief that competition and deregulation were inevitable
24 and that other states needed to get on the bandwagon or they would be left behind
25 by California and the handful of jurisdictions that were seriously looking at this
26 issue. Arizona was not immune to this growing enthusiasm for restructuring and

1 deregulation, and the Commission opened a docket investigating electric industry
2 restructuring in 1994, although there was little activity in that docket until 1996,
3 when the Commission enacted the first version of the Electric Competition Rules.

4
5 **Q. DID THESE RULES ATTEMPT TO CHANGE THE VERTICALLY**
6 **INTEGRATED STRUCTURE OF APS OR REQUIRE DIVESTITURE OF**
7 **THE COMPANY'S GENERATION?**

8
9 A. No. In fact, the Commission rejected mandatory divestiture, although its generic
10 "stranded cost" order in 1997 did allow it as an optional means of valuing an
11 electric utility's "stranded costs." That position appeared to suddenly change in
12 1998, and by August of that year, mandatory divestiture was added to the Electric
13 Competition Rules as an "emergency" measure. APS was successful, however, in
14 persuading the Commission to allow divestiture to take place to an affiliate of APS
15 rather than to one of the then-emerging merchant generators. This switch in
16 regulatory policy from vertical integration to mandatory divestiture of generation
17 was further reflected in the 1998 three-way settlement among APS, TEP and
18 Commission Staff, as well as the finalization of the "emergency" Electric
19 Competition Rules in December of 1998.

20
21 **Q. DIDN'T THE COMMISSION REVISIT THE ELECTRIC COMPETITION**
22 **RULES IN 1999?**

23 A. Yes. The "permanent" 1998 Electric Competition Rules lasted less than a month
24 before a new Commission set them aside. But although several aspects of the
25 Rules were subsequently changed, the Commission held steadfastly by the concept
26 of mandatory divestiture in the set of Electric Competition Rules that were
approved early in the fall of 1999.

Q. HOW DID THE 1999 APS SETTLEMENT AGREEMENT FIT INTO ALL
THIS?

1 A. Just as had the failed 1998 three-way settlement, the 1999 Settlement called for
2 divestiture of generation to an affiliate of APS. This was changed slightly by the
3 Commission to be a direct subsidiary of Pinnacle West rather than a subsidiary of
4 APS, as had been envisioned by the actual settlement itself. APS also was
5 permitted an additional two years to accomplish divestiture as compared to the
6 requirements of the Electric Competition Rules.

7
8 The 1999 Settlement also called for a Code of Conduct, as did the 1999 version of
9 the Electric Competition Rules. This Code of Conduct was approved by the
10 Commission in early 2000 and, I was told at the time, effectively prohibited APS
11 from constructing new generation even during the "window" prior to divestiture,
12 which now extended through 2002. APS agreed to this restriction because, given
13 the Commission's clear preference for divesting generation, it would have been
14 imprudent, even unimaginable, for APS to construct generation that it then would
15 have to divest before such generation was, for the most part, completed and placed
16 into service.

17 **Q. WAS ARIZONA ALONE IN REQUIRING DIVESTITURE OF**
18 **GENERATION?**

19 A. No. In the West, California, Nevada and Montana all required divestiture but did
20 not have the foresight to allow for that divestiture to be to an affiliate of the
21 incumbent vertically integrated utility. Divestiture also was required or
22 encouraged elsewhere in the country.

23 **Q. DID THE REQUIREMENT TO DIVEST APS GENERATION AND TO**
24 **NOT CONSTRUCT NEW GENERATION AT APS AFFECT THE**
25 **COMPANY'S OBLIGATION TO RELIABLY SERVE AS PROVIDER OF**
26 **LAST RESORT WITHIN ITS SERVICE AREA OR TO PLAN FOR ITS**
FUTURE NEEDS IN THAT REGARD?

1 A. No, but it did complicate that effort. Owning generation gives a utility the ultimate
2 physical hedge against market risk and provides operational and financial
3 flexibility not easily obtainable through mere contracts for power. Divestiture also
4 meant that APS' superior capital raising ability could not be used to finance any
5 needed new resources. Building such new resources at PWEC was clearly a
6 "second best" option compared with continued integration of APS, but it was just
7 as clearly the best option then available to discharge the Company's public service
8 obligation.

9
10 **Q. HOW DID ALL THESE REGULATORY EVENTS INFLUENCE YOUR
RESOURCE PLANNING PROCESS?**

11 A. With the Commission's Electric Competition Rules finally approved and the 1999
12 APS Settlement in effect, generation planning shifted emphasis from the regulated
13 to the competitive arena. APS agreed to shift its generation to a competitive
14 generation affiliate, PWEC, which was created in September 1999. However, we
15 continued to view the primary mission of that generation affiliate as the provision
16 of reliable and economical power to APS customers, albeit at market determined
17 rates under FERC jurisdiction rather than traditional Commission-regulated cost-
18 of-service prices. The resource planning process at APS and subsequently at
19 PWEC continued to explore various generation alternatives and market and
20 regulatory scenarios to quantify inherent risk associated with all of these events.
21 For example, we reviewed the possible implications of the generation transfer for
22 APS. In June 1999, we conducted an analysis entitled "1999 Planning Scenarios
23 Risk Assessment." The analysis concluded that blending existing APS generation
24 with the new construction being planned would result in lower costs to APS
25 customers than would open market purchases. This confirmed to APS the wisdom
26

1 of maintaining this blend of generation in an affiliate where it could still be
2 dedicated to serving APS.

3
4 **Q. DID EVENTS GO AS HAD BEEN ANTICIPATED, EITHER IN ARIZONA
OR IN THESE OTHER STATES TO WHICH YOU REFERRED?**

5 A. Yes and no. During 1998 and most of 1999 wholesale power prices were, as
6 expected, very low. Then in 2000, the situation changed dramatically. Power
7 prices began to soar in the California market. Brownouts and blackouts occurred in
8 California and spread to other parts of the West. Although APS had anticipated that
9 electric markets, like all commodity markets, would be volatile and had determined
10 even during the "soft" power price period of 1998-1999 to protect its customers
11 from that volatility and to ensure reliability here in the Valley, I cannot claim that
12 we predicted the full scope of the ensuing disaster. Thus, it was decided in 2001
13 that a study should be done to analyze the impact on APS and APS customers of
14 various possible regulatory reactions to the California situation.

15
16 **Q. WHAT WERE THE SCOPE AND RESULTS OF THIS 2001 MARKET
STRUCTURE STUDY?**

17 A. In early 2001, at the height of the California crisis, APS Resource Planning
18 undertook an analysis of the impact differing market structures would have on APS
19 customers. We identified four potential alternatives for analysis:

- 20 • Current Path (Divestiture and Deregulation)
- 21 • Current Path (Bilateral Agreement with PVEC for full-requirements)
- 22 • Partial Regulation
- 23 • Return to Vertical Integration

24 Under the Current Path-Divestiture and Deregulation scenario, APS would transfer
25 its generation assets to PVEC and acquire all of its needs from the competitive
26

1 market as required by the Competition Rules and the 1999 Settlement Agreement.
2 The PWEC generation assets (including the transferred APS assets) could still
3 serve APS, but at market-determined prices, and would compete for sales in the
4 general wholesale market, where its diverse and low-cost portfolio would provide
5 significant competitive advantages.

6 Under the Current Path-Bilateral Contract scenario, APS would also continue with
7 the planned transfer of its generation assets to PWEC, as required by the Arizona
8 Competition Rules and the 1999 Settlement. PWEC and Pinnacle West would then
9 seek Commission permission to provide a "full requirements" service to APS
10 reflecting the cost of the combined (at PWEC) portfolio of APS and PWEC
11 generation as well as the cost of supplemental power purchased from the
12 competitive market. This scenario formed the basis of our proposal in the fall of
13 2001 for a purchased power agreement between PWEC and APS and a
14 corresponding request for a partial variance to the Electric Competition Rules.
15

16 Under the Partial Regulation scenario, APS would retain its existing generation
17 assets under cost-based regulation and obtain all of its unmet needs from the
18 wholesale market. PWEC's new generation assets would compete for sales in the
19 wholesale market. This scenario was inconsistent with either the competitive
20 model required under the Electric Competition Rules or the traditional regulatory
21 scheme in effect for many decades prior to the Electric Competition Rules. It also
22 was not practical in any event, because WP-4 and WP-5 were necessary for reliable
23 service to APS customers in the Valley. Thus, we did not fully complete this
24 particular analysis.
25
26

1 Under the Return to Full Regulation scenario, APS would continue to own
2 generation assets – both its own existing assets and the assets being constructed by
3 its affiliate PWEC. These assets would be included in the Company's rate base
4 under cost-of-service ratemaking, including recovery of cost of capital. The
5 wholesale market would still fill a vital role of providing "economy energy" sales
6 and purchases as well as capacity to cover any deficit during periods of high
7 demand. It would also provide an alternative for future load growth, but APS
8 could continue to have the option of building new utility-owned generation assets
9 as needed to meet future customer demands.

10 **Q. WHAT WERE THE RESULTS OF THIS ANALYSIS?**

11 A. Because Option 4 (Return to Vertical Integration) did not materially differ from
12 Option 2, I have focused my analysis here on Option 4. Our analysis showed
13 significant volatility inherent in the deregulation scenarios. The Return to Vertical
14 Integration scenario was found to be the most beneficial and financially attractive
15 scenario for APS customers. I have calculated the savings anticipated for APS
16 customers from Option 4 as compared to Option 1. This scenario provided average
17 savings in the range of \$250 million for our customers just in 2005 alone. The
18 savings for other years were comparable. And although a large amount of these
19 savings come from the continued cost-of-service regulation of the existing APS
20 generation, the analysis also showed anticipated 2005 customer savings in the
21 range of \$22-74 million from the new PWEC generation.
22

23 **Q. HAVE YOU PREPARED A TIMELINE THAT PUTS ALL OF THESE**
24 **REGULATORY, MARKET AND APS PLANNING AND CONSTRUCTION**
EVENTS INTO CONTEXT?

25 A. It would be impossible to do that on a single chart or graph. There were just too
26 many events that led to the current situation, as I have described in my testimony.

1 However, as noted in my Summary, I have prepared a simplified timeline as
2 Attachment AB-1 that depicts at least the major events in Arizona, the region and
3 nation, and for APS/PWEC planning and construction of the PWEC assets. This
4 timeline will allow the reader to get a better feeling as to how all of these various
5 pieces fit together.

6
7 V. ECONOMIC ANALYSES OF THE PWEC ASSETS

8 Q. **YOU HAVE TESTIFIED THAT YOU CONDUCTED ECONOMIC**
9 **ANALYSES IN ADDITION TO THAT DISCUSSED IN CONJUNCTION**
10 **WITH THE POSSIBLE REGULATORY REACTIONS TO THE**
11 **CALIFORNIA ENERGY CRISIS THAT SUPPORTED THESE CONCERNS**
12 **ABOUT RELIANCE ON THE WHOLESALE MARKET. WOULD YOU**
13 **DISCUSS THEM IN MORE DETAIL?**

14 A. Yes. As I have stated previously in my testimony, economic assessments of the
15 economic viability of constructing these units were made repeatedly. Project IRR
16 was estimated based on our forecast of the wholesale market revenues and project
17 costs. We also continued with conventional revenue requirement measurements
18 through analyses of busbar costs. In fact, we computed each project's revenue
19 requirements / busbar cost at every major milestone during the planning and initial
20 construction phases. We compared the relative competitiveness of these new units,
21 both combined with the existing APS generation that was to be divested to PWEC
22 and separately, with other merchant generators in the vicinity or to spot wholesale
23 market prices. These results supported our conclusion that we were prudently
24 planning and constructing these units for APS customers.

25 Q. **WILL YOU DESCRIBE THE RESULTS OF YOUR IRR STUDIES FOR**
26 **THE PWEC ASSETS UNDER CONSIDERATION IN THIS PROCEEDING?**

A. Yes. During the course of the 36-month period of that encompassed the planning
and initial construction phases of the PWEC assets, we prepared numerous IRR
analyses on the Redhawk units, WP-4, WP-5 and Saguaro CT-3. Attachment AB-5

1 summarizes IRR results for the each of the PWEC assets. Each and every study
2 represented this Attachment showed life-cycle IRR for Redhawk of 12% or better
3 using then-anticipated market prices. Similar studies for WP-4 and WP-5 were also
4 performed and the results of these studies are also provided on Attachment AB-5.
5 Since Saguaro CT-3 was completed with an accelerated schedule, two study results
6 are provided for this project in Attachment AB-5.

7
8 **Q. PLEASE DISCUSS YOUR REVENUE REQUIREMENT / BUSBAR COST STUDIES.**

9 A. We prepared busbar cost studies for the PWEC generation using the same set of
10 operating and fuel cost assumptions used for our IRR analyses. Both the IRR and
11 busbar analyses indicated that the PWEC generation assets were prudent economic
12 resource additions for the Company and its customers if they could be constructed
13 at reasonable cost. However, because the assets were needed also for reliability, it
14 was equally important for them to be timely completed from the viewpoint of APS
15 system requirements.

16
17 **Q. HOW DID THESE IRR MODEL RESULTS SHOW ANTICIPATED BENEFITS TO APS CUSTOMERS?**

18 A. As I explained earlier in my testimony, the higher a project's IRR, the lower the
19 cost the project will be for customers under a regulated costs-of-service regulatory
20 regime. I have reviewed the previously developed IRR results provided in
21 Attachment AB-5 referenced above and compared them with the potential project
22 revenue requirements under cost-of-service regulation. I have used cost-of-capital
23 assumptions of the time, which were somewhat higher than what APS is requesting
24 in this case. This tends to overstate the cost-of-service revenue requirement as
25 compared to today. Operating and market price assumptions were also based on the
26 same data as the original IRR and busbar cost analyses.

1 My analysis shows that rate-basing the PWEC reliability assets could have been
2 anticipated to yield a benefit ranging from approximately \$496 million to \$615
3 million in net present value over the life of the projects. The discount rates used in
4 my analysis are between 8.25% and 7.1%, after tax, the former of which was
5 consistent with the average cost-of-capital also used in the original IRR and busbar
6 analyses, while the latter reflects the after-tax cost-of-capital requested in this
7 proceeding. Once again these results and conclusions are drawn from studies
8 conducted while these assets were being planned and justified to management and
9 thus are the studies that directly relate to the prudence of constructing the PWEC
10 assets to serve APS.

11 VI. THE PWEC GENERATION ASSETS WERE PRUDENTLY AND TIMELY
12 CONSTRUCTED, AND THEIR AS-BUILT COST WAS REASONABLE

13 Q. **WOULD YOU PLEASE DISCUSS THE TIME DURATION BETWEEN**
14 **PLANNING, CONSTRUCTION AND IN-SERVICE OF YOUR**
RELIABILITY UNITS?

15 A. The assets constructed by PWEC were state-of-the-art combined cycle and
16 combustion turbine units. Unlike previously constructed long lead-time (10-20
17 years) nuclear and coal units, the reliability assets took less than three years to
18 complete. The Redhawk project was announced in late September 1999, received
19 its CEC permit on February 23, 2000, finalized its engineering, procurement and
20 construction ("EPC") contract on September 2000, began its construction on late
21 November 2000, and was brought on-line in summer of 2002. This was all in
22 accordance with the accelerated schedule established for Redhawk's completion in
23 the third quarter of 2000.

24 WP-4 and WP-5 were announced to the public in late April 1999 and received their
25 CEC permit on February 17, 2000. The WP-4 EPC contract was awarded in
26 November 1999. Construction began the following June and was completed before

1 the Summer of 2001. WP- 5's EPC contract was signed in May 2001, construction
2 began September 2001, and the projected in-service date for this unit is July 2003.

3 The Saguaro CT-3 project was awarded an EPC contract in August 2001.
4 Construction began October of 2001, and commercial operation was achieved
5 before the summer of 2002. Because of its size, Saguaro CT-3 did not require a
6 CEC.

7
8 In each of these instances, the PWEC units were constructed in time to address the
9 Company's reliability needs. And in no instance was there a significant overrun in
10 the construction schedule anticipated when construction actually began.

11
12 **Q. HOW WERE THE CONSTRUCTION COST ESTIMATES DEVELOPED
FOR THE RELIABILITY ASSETS?**

13 A. The construction cost estimates for the Redhawk and West Phoenix units can be
14 characterized into four phases: (1) the planning phase; (2) the development phase;
15 (3) the phase just before construction commencement; and (4) the construction
16 phase. I might also add that there were also unique events specific to each project.
17 For example, the construction and timing of WP-4 were accelerated by turbine
18 availability from a previously suspended project. Both WP-5 and Redhawk were at
19 one time considered as jointly-owned projects, and Saguaro CT-3 was built, in part,
20 in lieu of continued use of temporary generation.

21
22 **Q. PLEASE EXPLAIN FURTHER HOW YOU ARRIVED AT THE
CONSTRUCTION COST ESTIMATES FOR EACH OF THESE PHASES IN
23 GENERAL?**

24 A. The construction cost estimate for most of our reliability generation during the
25 planning phase followed the normal standards of generation planning process at
26 APS. The generic technology-specific construction cost data was provided by our

1 Engineering Department. This allowed us to compare a project's relative
2 economics to another.

3 In the development phase, site-specific construction cost estimates were prepared
4 based on certain contacts with major equipment suppliers and the EPC contractor.
5 This phase did not consider more detailed cost estimates associated with the project
6 transmission, water and specific equipment design. Such site-specific and
7 transmission-related studies are performed in tandem later in the project.
8

9 In the case of the PWEC assets, the major equipment suppliers, project design
10 work, and engineering services were obtained through competitive RFPs to
11 minimize cost. Then, the project construction cost estimates were refined further
12 through the competitive procurement process itself. These estimates were finally
13 supplemented with other ancillary project equipment costs. Taken together, these
14 steps provided the best estimate available prior to the construction phase itself.

15 The construction cost estimates and/or commitments (also know as budgets) were
16 monitored regularly from this time forward. Contractual, environmental or
17 regulatory requirements were the most common reasons for further modifications
18 of project cost from the previous phase. These direct project costs along with
19 interest accumulated during construction ("IDC") became the final project
20 construction costs.
21

22 **Q. HOW DID WP-4'S "AS-BUILT" COSTS COMPARE TO THE PLANNING**
23 **ESTIMATED AMOUNT PRIOR TO CONSTRUCTION COMPLETION?**

24 A. During the planning phase of the project, the construction cost data was estimated
25 based on our engineering judgments and input from the EPC contractor. In June
26 2000, and prior to construction, the cost estimate of WP-4 was set at \$75 million,

1 not including IDC and any necessary spare parts inventory. WP-4's final cost was
2 \$78 million, including spare parts and allowing for an incentive payment to the
3 EPC contractor for its timely construction of this much-needed facility.

4 **Q. WHAT CONSTRUCTION COST DATA FOR WP-5 UNIT DO YOU HAVE?**

5 A. During the initial planning stages (November 1999) for its two-on-one combined
6 cycle configuration, WP-5's preliminary construction cost data was estimated to be
7 \$251 million, which was only an engineering estimate made without any input
8 from the EPC contractor and did not include additional environmental or
9 transmission-related equipment. That estimate was revised upward by \$30 million
10 taking into consideration input from the EPC contractor, major equipment
11 contractors. The present as-built estimate for WP-5 is \$292 million, including spare
12 parts and transmission improvements. I do not consider this figure to be
13 significantly higher than the final pre-construction estimate.

14
15 **Q. DO YOU HAVE A SIMILAR ANALYSIS OF THE TWO REDHAWK UNITS?**

16 A. Yes. The Redhawk units were initially (September 1999) planned as four 500 MW
17 units using Westinghouse turbines and were estimated to cost roughly \$1 billion in
18 total based on the preliminary engineering estimate. The failed partnership with
19 Reliant did allow APS to substitute GE turbines, which facilitated an in-service
20 date coincident with APS needs, albeit at a somewhat higher cost. Redhawk project
21 cost estimates were also revised to include additional transmission line costs and
22 spare parts. Thus, in July 2001, the new project cost for the four units was
23 estimated to be \$1.13 billion based on the actual contracts awarded for the project.
24 The as-built cost of Redhawk 1 and 2 was \$572 million, only slightly more on a per
25
26

1 unit basis than the final estimate. PWEC wrote off Unit 3 and 4 costs of
2 approximately \$50 million, and these costs are not a part of this rate proceeding.

3
4 **Q. PLEASE CONTINUE BY DISCUSSING SAGUARO CT-3?**

5 A. The schedule for the Saguaro simple cycle project was for it to be in service to
6 meet APS 2002 peak load at a cost estimated at \$40 million. Actual as-built cost
7 was a little below that estimate, or \$37 million. This unit took the place of the
8 temporary rental turbines used in 2001, which I have previously discussed.

9 **Q. HOW DOES THE COST OF THE PWEC UNITS COMPARE WITH THE
10 COST OF SIMILAR UNITS BUILT AT THE SAME TIME IN ARIZONA?**

11 A. Because the main cost components (gas turbines, steam turbine and steam
12 generating equipment) are common to any combined cycle installation, there is
13 little room for significant cost variations from one installation to another. However,
14 based on public data released by other builders on their projected costs for like
15 installations, the PWEC unit costs are comparable to and would appear to be
16 competitive with similar units of the same vintage. In fact, these assets were
17 roughly 5% less per installed kW (\$570/kW versus \$596/kW) than the average of
18 other similarly-vintaged plants in Arizona. Of course, as I noted earlier, the actual
19 book value of the PWEC assets asked for inclusion in the Company's rate base is
20 somewhat less due to the depreciation and deferred taxes from their in-service date
21 through their estimated date of acquisition by APS.

22 **Q. HOW DID YOU KEEP THE COST OF THE PWEC UNITS WITHIN A
23 REASONABLE RANGE?**

24 A. In addition to using competitive RFPs where appropriate, PWEC used a series of
25 incentives for the contractors to meet or beat scheduled dates and entered in other
26 contracting partnerships to keep both the cost targets and service date schedules

1 within a reasonable range. These strategic alliances, along with having PWEC
2 staff on site during the construction phase, allowed these projects to be completed
3 at a reasonable cost.

4 **Q. WERE CONSTRUCTION COSTS FOR THE REDHAWK AND WEST**
5 **PHOENIX PROJECTS REVIEWED BY AN INDEPENDENT**
6 **CONSULTANT?**

7 **A.** Yes. In 2000/2001, PWEC retained Stone and Webster, an engineering and energy
8 consulting firm, to review Redhawk-1 and Redhawk-2 and also WP-4. (At this
9 time, WP-5's major contracts were being negotiated and were not available to
10 S&W for their review. However, they were not materially different than those for
11 Redhawk.) In their written report, Stone and Webster reviewed: 1) plant design and
12 major equipment; 2) the EPC contracts; 3) combustion turbine supply and
13 installation; 4) the heat recovery steam generator acquisition; 5) the steam turbine
14 acquisition; 6) the brine concentrator acquisition; 7) all transmission agreements; 8)
15 equipment performance and availability; 9) natural gas availability; 10) proposed
16 implementation schedule; 11) estimated capital costs; 12) projected O&M; 13)
17 permitting requirements and permitting status; and 14) environmental assessment
18 of the facility. Stone and Webster concluded that both Redhawk and West Phoenix
19 were being constructed in full conformance with accepted industry practices and
20 anticipated project costs were reasonable.

21 **VII. CONCLUSION**

22 **Q. WOULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?**

23 **A.** First of all, the PWEC assets were built to serve APS customer load and have done
24 so. Their unique location near the load center makes them, both in terms of
25 reliability and economics, superior generating assets to other alternatives
26 considered at the time. This did not happen by chance, but was instead the result of

1 a prudent and comprehensive resource planning process. Secondly, the results of
2 the recent Track B power supply solicitation conducted by APS clearly confirm
3 what our resources studies have repeatedly shown. The PWEC assets are necessary
4 to reliably serve APS customers both in the short and long-term. Third, the PWEC
5 assets provide significant operating benefits to the Company and its customers by
6 providing needed voltage support and the flexibility to economically displace less
7 efficient generation. Finally, these assets will be acquired by APS and included in
8 the rate base at their 2004 depreciated cost. This provides significant long-term
9 economic savings to APS customers.

10 **Q. DOES THAT CONCLUDE YOUR WRITTEN DIRECT TESTIMONY?**

11 **A. Yes.**
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APPENDIX A

STATEMENT OF WITNESS QUALIFICATIONS

Ajit P. Bhatti is Vice President of Resource Planning for Arizona Public Service Company. Mr. Bhatti was elected to this position in December 2002 and is responsible for developing generation plans and evaluating strategic initiatives for APS. He is a veteran of the electric utility industry with over thirty (30) years of experience in Western generation and transmission system modeling and planning.

Mr. Bhatti joined the Company in 1973 and has held management positions at varying capacities since June 1986. In 1990, he was named Manager of the Resource Planning Department and in 1998 Mr. Bhatti was named Director of the same. In that position, he was responsible for identifying electric generation deficits of the APS system and providing long-range planning of the generation resources. In 2000, Mr. Bhatti was elected to Vice President of Generation Planning for Pinnacle West Energy Corporation (the then newly-formed subsidiary of Pinnacle West Capital Corporation) and was responsible for providing long-range planning for the enterprise' generation resources.

Mr. Bhatti maintains extensive knowledge in the Western generation and transmission systems and power markets. During his career, he has developed computer models to simulate local and regional electric systems. He has extensive expertise in utility integrated resource planning, generation modeling, generation technology economic analysis and system planning. He was extensively involved in originating the Company's generation strategies with PacifiCorp that resulted in substantial benefits for APS' customers.

Mr. Bhatti has led regional planning task forces and authored reports related to regional transmission plans in the Southwest. He has previously testified before the Arizona Corporation Commission related to the Company's IRP filings. He has also provided testimony in proceedings before the Interstate Commerce Commission (now the Surface Transportation Board of the United States Department of Transportation). Those proceedings were initiated by the Company in 1994 against the Santa Fe Railway (now the Burlington Northern Santa Fe Railway) to investigate the reasonableness of rail rates charged by the

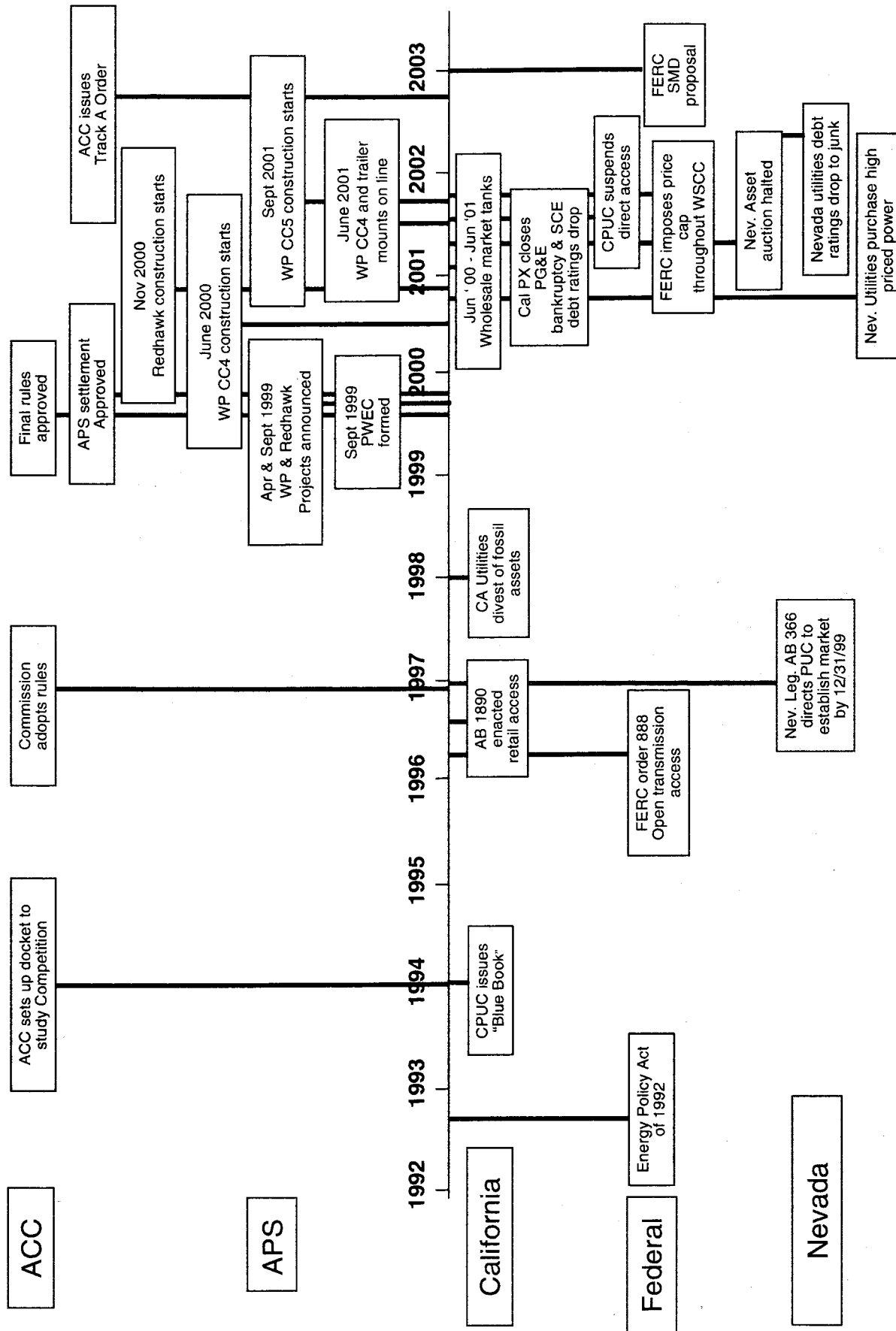
rail carrier for transport of coal from mines in New Mexico to the Company's power plant in Arizona. Mr. Bhatti's testimony addressed the modeling of the electric system to demonstrate the impact that tariffs charged by the railroad had upon the dispatching of APS electric generating assets.

Mr. Bhatti has made presentations to rating agencies, financial analysts and to industry forums. He is routinely called on by the Company's Board of Directors to provide insights on the Western electric markets and the Company's generation plans.

Mr. Bhatti holds Bachelor and Masters Degrees in Electrical Engineering from New Mexico State University. He has been a registered professional engineer specializing in electricity in the State of Arizona since February 1977.

Attachments

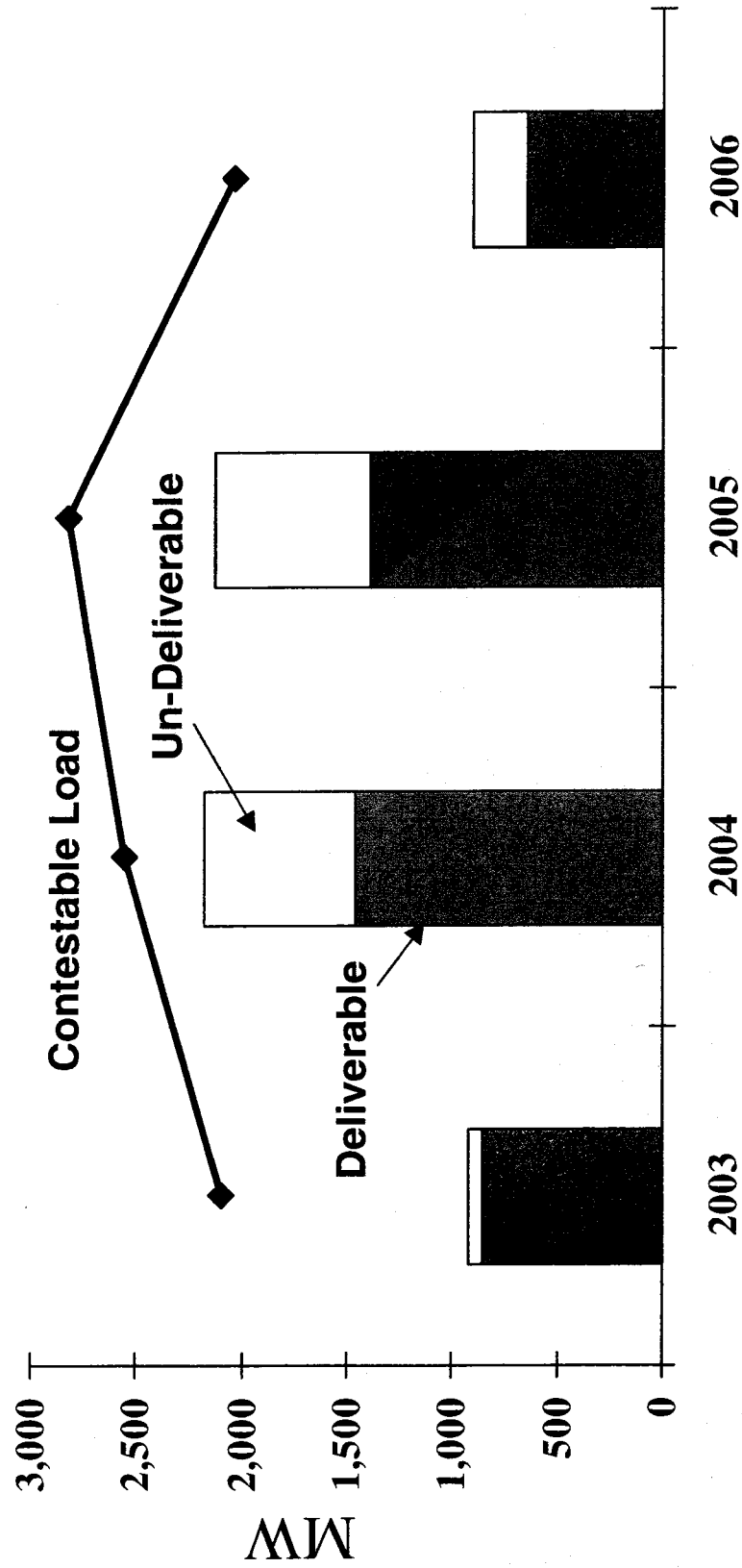
Time Lines Related to Restructuring Electric Industry



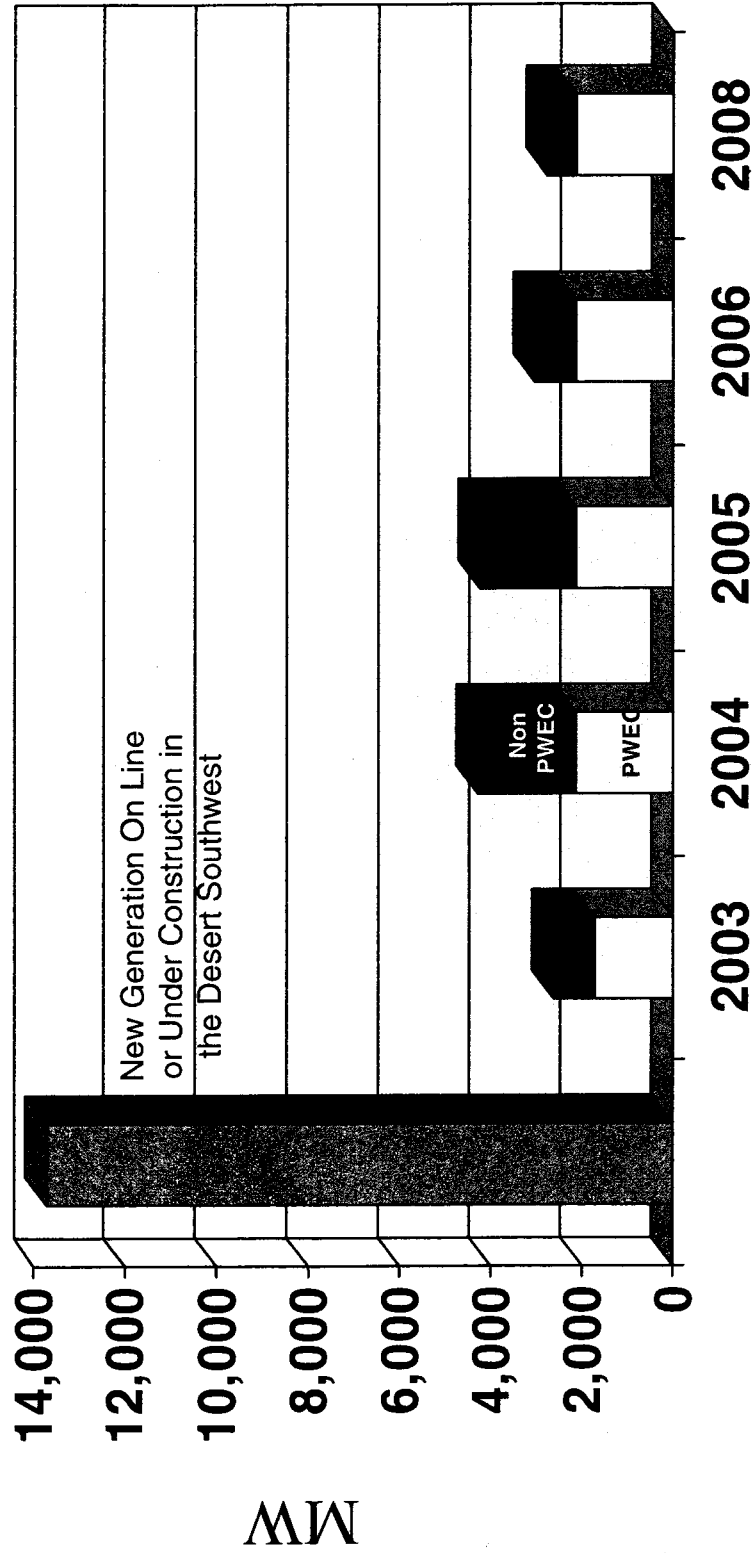
APS SUMMER SUPPLY & DEMAND BALANCE **2003 Long Range Forecast**

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
A. LOAD REQUIREMENTS										
1 <u>SYSTEM DEMAND</u>										
2 <u>PEAK DEMAND</u>	5,723	6,023	6,269	6,522	6,787	7,064	7,357	7,667	7,914	8,127
3 <u>ANNUAL LOAD GROWTH %</u>		5.2	4.1	4.0	4.1	4.1	4.1	4.2	3.2	2.7
4 <u>RELIABILITY</u>										
5 <u>RESERVE REQUIREMENTS</u>	725	787	823	860	898	939	981	1,027	1,062	1,093
6 <u>TOTAL LOAD REQUIREMENTS</u>	6,448	6,810	7,092	7,382	7,685	8,003	8,338	8,694	8,976	9,220
B. EXISTING GENERATION & PURCHASED POWER RESOURCES										
7 <u>EXISTING GENERATION RESOURCES</u>										
8 <u>APS EXISTING GENERATION</u>	3,981	4,007	4,002	4,029	4,029	4,055	4,055	4,055	4,055	4,055
9 <u>SEASONAL VARIATION</u>	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)
10 <u>CAPACITY ON MAINTENANCE</u>										
11 <u>TOTAL</u>	3,927	3,953	3,948	3,975	3,975	4,001	4,001	4,001	4,001	4,001
12 <u>PURCHASED POWER RESOURCES</u>										
13 <u>SRP - FIRM</u>	288	295	302	310	318	326	334	342	351	360
14 <u>SRP - CONTINGENT</u>	62	62	62	62	62	62	62	62	62	62
15 <u>PACIFICORP DIV EXCH</u>	480	480	480	480	480	480	480	480	480	480
16 <u>TOTAL PURCHASES</u>	830	837	844	852	860	868	876	884	893	902
17 <u>TOTAL EXISTING RESOURCES</u>	4,757	4,790	4,792	4,827	4,834	4,869	4,877	4,885	4,894	4,902
C. NEW RESOURCES										
18 <u>ENVIRONMENTAL PORTFOLIO</u>										
19 <u>WP - 4</u>	4	10	18	18	21	22	22	23	23	24
20 <u>WP - 5</u>	110	110	110	110	110	110	110	110	110	110
21 <u>REDHAWK CC 1-2</u>	524	524	524	524	524	524	524	524	524	524
22 <u>SAGUARO SC 3</u>	990	990	990	990	990	990	990	990	990	990
23 <u>PPL's SUNDANCE CTs</u>	76	76	76	76	76	76	76	76	76	76
24 <u>MARKET PURCHASE</u>	112	150	150							
25 <u>TOTAL</u>	1,941	1,860	1,868	1,718	1,721	1,722	1,722	1,723	1,723	1,724
26 <u>TOTAL EXISTING AND NEW RESOURCES</u>	6,698	6,650	6,660	6,545	6,555	6,591	6,599	6,608	6,617	6,626
D. TOTAL RESOURCES OVER / (UNDER)										
27 D. TOTAL RESOURCES OVER / (UNDER)	250	(161)	(432)	(837)	(1,130)	(1,412)	(1,740)	(2,086)	(2,360)	(2,594)
E. OVER / (UNDER) WITHOUT T&C										
28 E. OVER / (UNDER) WITHOUT T&C					(1,557)	(1,849)	(2,186)	(2,541)	(2,825)	(3,069)

Non-PWEC Response To APS RFP

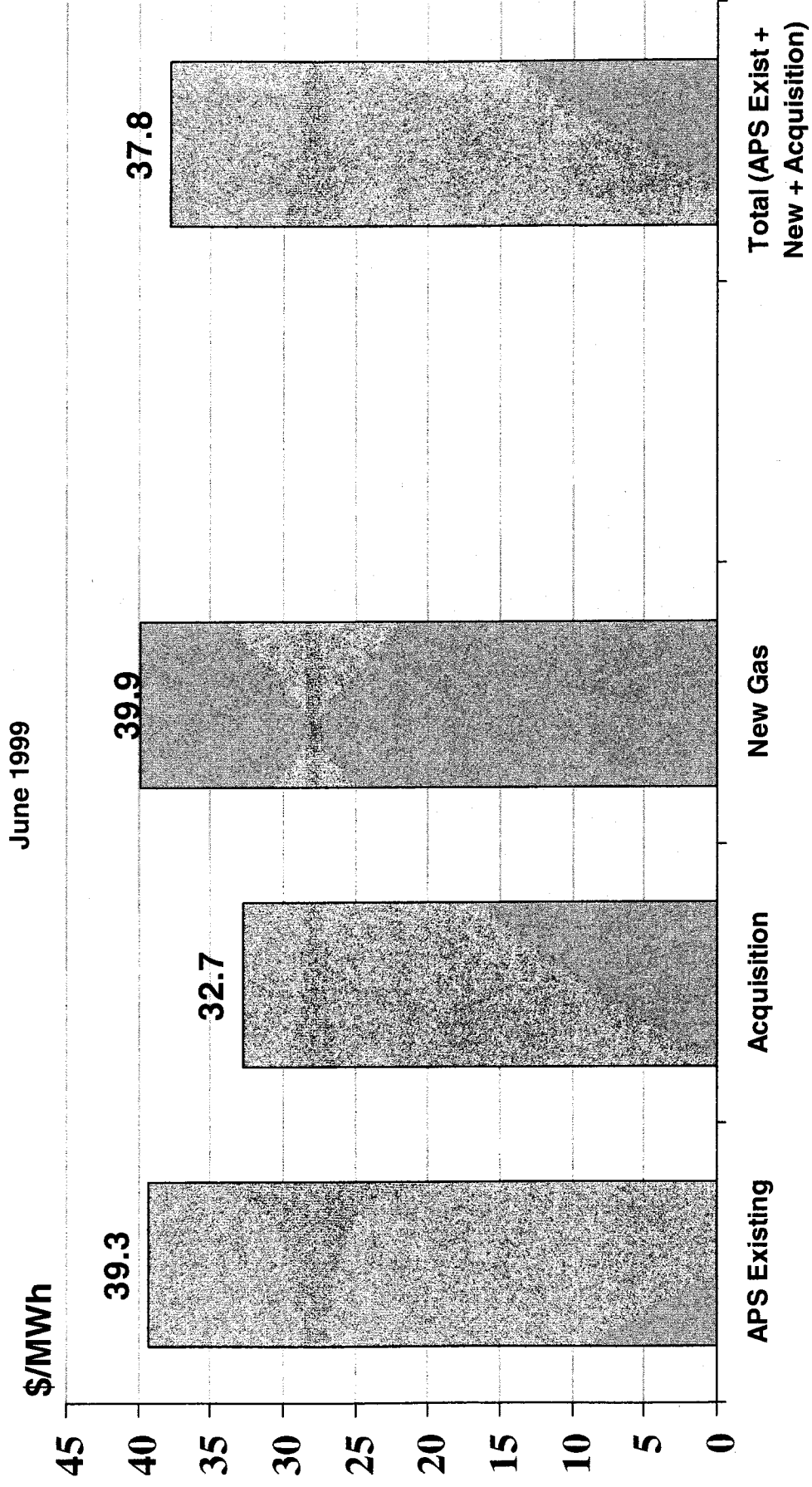


Response To APS RFP



Bids Received by APS

2000-2009 (1999 LRF BUSBAR STUDY) 10-Year Levelized Generation Busbar Cost (w/ Interchange Sales)



Redhawk Project Estimated IRR

Study Date	Project In-Service	Const. Cost Estimate \$M	Life-time IRR %	Comments
<u>All Four Units 1-2-3-4</u>				
1/13/1999	02/03/04/05	894	13.7	Initial Planning studies using construction cost data estimated based Engineering judgements. Issued RFP for turbines 8/99. PWEC formed 9/27/99. Board approval and public announcement of project 9/29/99. PCEC permit application 10/20/99
2/10/1999	02/03/04/05	869	15.2	
2/10/1999	04/05/06/07	904	15.2	
4/23/1999	02/03/04/05	869	16.5	
7/11/1999	03/04/05/07	876	16.0	Based on studies prepared before and after partnership with Reliant.
9/11/1999	03/04/05/07	876	16.5	
11/19/1999	03/04/05/07	1029	15.1	
6/16/2000	02/02/05/06	1128	17.2	
8/22/2000	02/02/05/06	1164	18.6	Reacting to the California high-market, 4000MW applied for CEC at PV. Redhawk #3 analyzed as CT. \$540M committed to Redhawk, \$440M cash out by 11/01 .
<u>Units 1&2 Only</u>				
7/3/2001	02/02	566	37.6	
10/15/2001	02/02	566	13.6	
12/13/2001	02/02	566	15.8	

West Phoenix CC4 Project Estimated IRR

Study Date	Project In-Service	Const. Cost Estimate \$M	Life-time IRR %	Comments
4/23/1999	2002	68	6.0	Project announcement 4/23/99.
5/21/1999	2002	70	15.0	IRR based on initial planning studies.
6/25/1999	2001	60	18.7	Project life: 32 year.
9/13/1999	2001	60	16.8	CEC applied 10/4/99.
6/16/2000	2001	75	11.0	CEC received 2/17/00. Final EPC cost estimate: \$75M. Construction began

West Phoenix CC5 Project Estimated IRR

Study Date	Project In-Service	Const. Cost Estimate \$M	Life-time		Comments
			IRR %		
5/18/1999	2002	220	13.3		IRR based on initial planning studies. Project life: 32 years. Partnership agreement with Calpine signed 9/99. CEC
6/25/1999	2002	222	12.6		
8/10/1999	2002	222	12.6		
6/16/2000	2003	280	15.9		Analysis prepared for 7/00 Board Meeting. IRR based on 50% ownership
8/16/2000	2002	146	15.3		
7/3/2001	2003	280	14.0		Based on 100% ownership after Calpine agreement dissolved in 01/01. Final EPC contract signed 5/01. Construction began
10/1/2001	2003	280	12.1		
6/24/2002	2003	289	10.3		\$116 M cash spent as of 1/02. Cost estimate of \$289 as of 7/02.
9/4/2002	2003	289	14.1		
11/4/2002	2003	289	14.9		

Saguaro CT3 Project Estimated IRR

Study Date	Project In-Service	Const. Cost Estimate \$M	Life-time IRR %	Comments
7/3/2001	2002	40	23.8	Air permit applied 5/01. Installed temporary 95MW CT @ \$18M in 6/01. Turbine cots \$23M, total project estimated \$40M. EPC contract finalized 7/01. \$16M cash
10/1/2001	2002	40	8.7	

Testimony
of
William H.
Heronymus, Ph.D.

TESTIMONY OF WILLIAM H. HIERONYMUS

ON BEHALF OF

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-___

VICE-PRESIDENT

CHARLES RIVER ASSOCIATES INC.

June 27, 2003

TABLE OF CONTENTS

I.	Qualifications.....	1
II.	Purpose and Summary of Testimony.....	5
III.	The Concept of Prudence.....	10
IV.	The Prudence of Constructing the Reliability Assets.....	12
V.	Review of APS System Planning Studies in 1998-2001.....	39
VI.	Construction Prudence.....	41
VII.	The PWEC Assets Are Used and Useful.....	46
VIII.	Lessons from the Track B Procurement.....	49
IX.	Observations on Future Wholesale Market Prices.....	51
X.	Conclusions.....	64
	Resume.....	Appendix A

DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-03-___)

I. QUALIFICATIONS

Q. Please state your name and business address.

A. My name is William H. Hieronymus. I am a Vice President of Charles River Associates Inc. My office address is 200 Clarendon Street, Boston, MA 02116.

Q. Please describe Charles River Associates Inc.

A. Charles River Associates Inc. (CRA) is an international economics and managing consulting firm with numerous offices in North America, Europe and Asia. Energy is a major corporate focus. CRA staff focusing primarily on electric and gas utilities, and associated environmental policies, totals approximately 80 people. A like-size group consults primarily on up-stream gas, oil and related chemicals industries.

Q. Please review your own personal background, focusing on those portions relevant to your participation in this case.

A. I am an economist by training, receiving a Ph.D. in economics from the University of Michigan in 1969. After military service, I entered consulting, joining CRA in 1973, primarily to work on major antitrust cases. However, the turmoil in energy industries, particularly the oil price crises of the 1970s, slowdowns in electricity and natural gas demand and related issues, caused me to shift my professional focus to energy economics in about 1975. Principal electricity issues in those days were

1 load forecasting, fuels market forecasting, resource planning, and new forms of rate
2 design and cost allocation to respond to increasing average costs of production.

3 Continuing into the late 1970s and early 1980s, I continued to focus on
4 electricity and related policy issues. Apart from policy issues such as PURPA and
5 related rate design and renewables procurement issues, the mainstay of my
6 consulting was resource planning, particularly what to do with plants under
7 construction given that the level of load growth was far less than had been
8 anticipated. Indeed, the last case in which I participated that had to do with siting a
9 wholly new utility-owned facility was in 1980. This turned out to be a landmark
10 event in western power markets. Failure to gain regulatory support for building a
11 large coal-fired facility led PG&E and SCE to abandon plans to build any major
12 new facilities. This was a major precursor to restructuring of the electricity industry
13 in California in the late 1990s (state-mandated QF contracts having led to very high
14 power costs) and to the supply-demand imbalance that was the primarily cause of
15 the power crisis in 2000-1.

16 Much of my utility consulting in the 1980s had to do with the large coal and
17 nuclear power plants that had begun in the early and mid 1970s and were just then
18 coming on line. This led to business issues about what to do with the power, how
19 to control construction and operating costs that seemingly were spiraling out of
20 control and ratebasing issues concerning these comparatively expensive new
21 facilities. I participated in many such proceedings, as well as management
22 consulting analyses of what to do with incomplete plants, including stopping
23 construction altogether or converting them to other fuels.

1 In 1988, the focus of my activities shifted abroad and to the subject of
2 restructuring electric utility markets. I worked for two years on the restructuring
3 and privatization of the U.K. electricity sector (and subsequently on changes to it)
4 and moved onto restructuring engagements in continental Europe, the Far East and,
5 toward the end of this period, formerly communist systems in Eastern Europe and
6 the U.S.S.R. During this time, I continued some work in this country as well.

7 I returned to the United States full time in 1993. Since that time I have
8 worked primarily on assignments relating to the restructuring of the North
9 American electricity industry. These have involved the design of power markets,
10 the evaluation of the competitive value of facilities, consideration of merger
11 candidates, various policy issues having to do with affiliate relations, restructuring
12 of companies, the structure of regional markets, market power and market power
13 mitigation, and so forth. A substantial part of my work in the past few years has
14 involved the west coast market. In addition to advising APS and Pinnacle West, I
15 have worked on the SEMPRA merger, the Duke acquisition of Westcoast Energy,
16 the various transactions involving Portland General, the PG&E bankruptcy, and
17 several of the regulatory proceedings involving the California and western power
18 markets, including the FERC cases concerning refunds for the crisis period and the
19 potential cancellation of the power contracts signed in 2001. My resume is attached
20 as Appendix A.

21 **Q. Please describe your relationship with Arizona Public Service and its affiliates.**

22 **A.** I first came into contact with APS in about 1975 when I was doing research for the
23 predecessor agency of the U.S. Department of Energy, specifically, the

1 development of state-level electricity load forecasting models for use by the agency
2 and state PUCs and planning agencies. I was first retained by APS in circa 1986 to
3 assist in planning for and execution of the Palo Verde Unit I rate case. I worked
4 intermittently with APS, primarily on Palo Verde nuclear plant issues throughout
5 the late 1980s and early 1990s. Subsequent to my return to the United States in
6 1993, I have worked with the Pinnacle West companies on a variety of strategy
7 issues, most of which have to degree or another dealt with the general area of
8 resource planning. Sometimes, my role has been to provide an independent view
9 and analysis to management. Other times it has been to offer independent advice to
10 in-house staff on methodologies and assumptions. I also have been tasked to
11 review and comment on in-house evolving strategies or pieces of analysis.
12 Sometimes it has been to provide a national or international view of trends and
13 developments to management. In this context, I have had a semi-continuous
14 familiarity with the resource planning tools and analyses of APS and Pinnacle
15 West.

16 I also have testified on behalf of the companies on a number of occasions,
17 most recently including Docket No. E-01345A-98-0473, et al; the settlement case
18 in which it was determined that APS generating assets would be transferred to what
19 became Pinnacle West Energy Company (PWEC); and also Docket No. E-01345A-
20 01-0822 in which PWEC and APS sought to establish a full requirements PPA
21 between the two companies. This latter proceeding subsequently was merged into
22 and ACC Docket E-00000A-02-0051, referred to as the "Track A" proceeding in
23 which I also testified.

1

2 **II. PURPOSE AND SUMMARY OF TESTIMONY**

3 **Q. What is the purpose of your testimony in this proceeding?**

4 A. My testimony relates generally to the question of whether the Pinnacle West
5 investment in the Redhawk, West Phoenix and Saguaro units properly is included
6 in APS's ratebase. The standard that I will employ is the "prudent investment test".
7 At the core of the test is the question, was the investment prudent in light of what
8 was known or reasonably knowable at the time that it was made? In this context, I
9 review the options available to Pinnacle West¹ for meeting APS's customers'
10 needs. As a closely related matter, I have reviewed, and provide an independent
11 commentary upon, Pinnacle West's resource planning and evaluation, particularly
12 as it relates to the "reliability assets" – West Phoenix 4 & 5, Saguaro and to
13 Redhawk. I also will discuss whether these assets are and will be "used and useful"
14 in meeting APS's load. Finally, while I do not believe that an analysis of the
15 contemporary economics of the PWEC Arizona generation, as opposed to one that
16 is based on the prudence of the investments when made, is appropriate for
17 evaluating the inclusion of these assets in APS's ratebase, I will discuss the likely
18 economics of the acquisition. In part, my discussion on this point will review what

¹ Generally, I will use the term "Pinnacle West" to refer to Pinnacle West Capital Corporation, the parent of both APS and Pinnacle West Energy Company (PWEC). In some cases, operative decisions were implemented at one subsidiary or the other. However, Pinnacle West Capital had fiduciary responsibilities for the entire enterprise, including both subsidiaries and also had ultimate responsibility for the conduct of the utility functions of APS regulated by this commission. Where referring specifically to either APS or to PWEC, I will use those terms. In discussing planning functions, I also will refer to Pinnacle West for the simple reason that planning functions sometimes were wholly in APS and sometimes were split between APS, PWEC and Pinnacle West corporate.

1 was learned in the "Track B" process about third party resources that might be
2 available to meet APS's load in the future.

3 Portions of this analysis compliment the testimony of Mr. Ajit Bhatti, who
4 testifies in some detail about many of these same matters from the perspective of
5 being the person in charge of resource planning for the company, both now and
6 during the period when the PWEC assets were planned and constructed.

7 **Q. Please summarize your conclusions.**

8 A. I conclude that the investment in West Phoenix, Redhawk and Saguaro was
9 prudent. The concept of prudence requires that management's decisions and
10 actions were reasonable given what was "known or knowable" at the time. This
11 standard is met readily with respect to these plants. Indeed, I conclude that
12 Pinnacle West management could not prudently have avoided building these
13 facilities, a far higher standard of prudence than ever has been applied to an electric
14 utility.

15 As I will discuss, these plants were built as part of an "APS-centric"
16 decision process that focused on assuring that APS's native load could be met
17 reliably and at reasonable costs. The APS-centric planning process was warranted
18 because Pinnacle West had a corporate obligation to APS and its customers.
19 Ordinarily, the result would have been that APS would have built or otherwise
20 acquired capacity itself. This was precluded by the Electric Competition Rules.
21 Instead, it was necessary for another Pinnacle West subsidiary, Pinnacle West
22 Energy Company (PWEC) to build the units. This concern with APS dictated the
23 location of the plants and the timing and amount of plant additions.

1 There can be no dispute that the type of plants that were built, gas combined
2 cycle and simple cycle units, was a prudent choice since these same plant types
3 account for virtually all new construction. The amount and timing of new
4 construction also was prudent. West Phoenix construction was commenced when it
5 became clear that new capacity was needed to meet the needs of the Valley load
6 pocket. No merchant had announced plans to build capacity within the load pocket
7 (and none are planned now). The West Phoenix additions were planned to come on
8 line when needed; their schedule was appropriate even with the benefit of hindsight.
9 Indeed, without West Phoenix 4 coming on line in 2001, it is unlikely that APS
10 could have met load without curtailment or other emergency measures.

11 The Saguaro unit was planned to meet load economically in the anticipated
12 shortage conditions of the summer of 2002. Without it, APS would have had to
13 take measures similar to those taken in the summer of 2001, which would have
14 been substantially more expensive than the annualized cost of Saguaro.

15 Redhawk was planned as a flexible future addition to meet load in the first
16 decade of the new millennium. Its timing was firmed and contracts were signed in
17 1999 in response to unanticipated load growth being experienced in the latter half
18 of the 1990s and in recognition that new merchant capacity was slow to build in
19 Arizona and not reliably available to meet APS's load. It was accelerated in 2000
20 to the schedule on which it was built in response to still more load growth in the
21 early summer of 2000 and to the beginning of the western electricity crisis. Until
22 well past the time when the investment was irrevocably committed it would not
23 have been reasonable for APS to rely on generation being built by others for the

1 market to meet its load at prices no higher than the cost of construction. Even in the
2 Track B solicitation, long after the electricity crisis had waned, only quite modest
3 and insufficient amounts of generation owned by others was made available for
4 contracts to meet APS's load.

5 I also reviewed APS's planning process and management decisions over the
6 period that is relevant to a prudence inquiry. I found that the process was highly
7 professional and, as already summarized, the decisions were prudent and intended
8 to assure that APS could meet load reliably and economically. There were no
9 infirmities of either the resource planning methods or decisions that, if cured, would
10 have caused Pinnacle West to have not built these units.

11 I also reviewed the construction costs of the PWEC Arizona units and
12 conclude that their costs were in the middle of the range of costs for similar units,
13 as best as can be ascertained from publicly available data. Given the biases in those
14 data, I conclude that the Pinnacle West units likely were below average in cost.
15 Hence I conclude that the management and execution of construction also was
16 prudent.

17 The PWEC assets also are "used and useful" to meeting the APS load.
18 Indeed, they have been so since coming on line. Effective July 1 of this year, they
19 will be dedicated by contract to meeting APS's summer loads. Based on current
20 forecasts, APS will be short, notwithstanding these contracts, by the time rates
21 decided in this proceeding are effective. APS will continue to need capacity
22 (beyond its owned capacity) in amounts greater than these assets in all years
23 thereafter.

1 My testimony also looks forward at power markets during the period after
2 the rates set in this proceeding come into effect. While I do not believe that such an
3 analysis should be central to this proceeding, I recognize that the likely economics
4 of ratebasing the assets may be of interest. Over most of the future, the Pinnacle
5 West assets are essentially certain to be cost effective since market prices will vary
6 around long run, marginal cost, essentially the cost of a new and similar unit.
7 Unlike the PWEC units, the units that set long run marginal costs will be built with
8 future and more inflated dollars that are not depreciated. Hence, there is a
9 predictable, continuous wedge of benefit from ratebasing the units. In the nearer
10 term, rate-basing the units might be more expensive than the market as a result of
11 the price-depressing effects of the new capacity coming on line in 2002-2003.
12 However, the "glut " period likely will be very brief. Western power markets will
13 cease to be in surplus, most likely beginning sometime between 2005 and 2008.
14 My best estimate is for 2007. In view of the "boom-bust" nature of power markets
15 in particular, and commodity markets generally, I do not expect that a new age of
16 capacity/load balance will be reached without another period of near-shortage and
17 resulting high prices. Indeed, my testimony will explain the inevitability of such
18 cyclic price spikes as were seen in 2000-2001 in the operation of competitive power
19 markets and the necessity of price spikes to the economics of building new
20 generation plants for the market. My expectation of a near-shortage and price spike
21 in the latter half of the decade, which occurs essentially at the same time that the
22 Track B contracts will expire, is amplified by knowledge of the reduced
23 circumstances of the merchants that built the majority of new capacity over the past

1 three years and the continuing regulatory difficulties they are experiencing in being
2 paid for long term contracts and other sales in Western power markets.

3 For these reasons, I conclude that ratebasing these assets is likely to be cost-
4 effective, relative to purchasing from the competitive wholesale market, for APS.

5 **Q. How is your testimony organized?**

6 A. Section III discusses the regulatory concept of "prudence," the test that I believe is
7 central to the ratebasing of these assets. Section IV analyzes the prudence of
8 decisions to construct the PWEC Arizona assets. Section V summarizes my review
9 of APS's system planning in the relevant period, drawing substantially on studies
10 addressed in the prior section. Section VI presents the results of benchmarking the
11 cost of the PWEC units against the cost of other units built during this period.
12 Section VII addresses the issue of whether the PWEC assets are used and useful to
13 APS's customers. Section VIII discusses lessons learned from the Track B
14 procurement. Section IX assesses near-term forward markets, and in particular
15 the likely timing and magnitude of the next price spike. More generally, it provides
16 qualitative information that supports a conclusion that ratebasing the PWEC assets
17 is likely to result in lower and less volatile prices than relying on the market for the
18 same amount of electricity. Section X briefly summarizes my main conclusions.

19

20 **III. The Concept of Prudence**

21 **Q. Please define what is meant by prudence in the context of utility regulation.**

22 A. As a general matter, the use of the term "prudence" refers to costs incurred by
23 regulated utilities. Most commonly, it is applied to tangible investments made by

1 the utility, though it also can be applied to other costs, such as costs for power
2 contracts. The concept of "prudent investment" relates to the utilities' ability, and
3 right under the form of regulation that has applied to utilities for at least the last 50
4 years, to include the prudently incurred cost of investments in ratebase and have a
5 reasonable opportunity to earn a fair return on the investment.

6 The definition of prudence contained in the regulations of the Arizona
7 Corporation Commission (A. A. C. R14-2-103) is characteristic of the term as used
8 in other jurisdictions as well. The definition is:

9 "Prudently invested" -- investments which under ordinary circumstances
10 would be deemed reasonable and not dishonest or obviously wasteful. All
11 investments shall be presumed to have been prudently made, and such
12 presumptions may be set aside only by clear and convincing evidence that
13 such investments were imprudent, when viewed in the light of all relevant
14 conditions known or which in the exercise of reasonable judgment should
15 have been known, at the time such investments were made."
16

17 The key elements of the definition are: (1) the strong presumption of
18 prudence; (2) the clear deference to management decision making implied by the
19 notion that imprudent investments are those that are dishonest and obviously
20 wasteful; and (3) the exclusive focus on what was known or reasonably knowable
21 at the time that decisions were made -- not at the time of a ratebasing decision or at
22 any other future date. The limitation of the analysis to focus on what was then
23 known or knowable means that "20-20 hindsight" is not permitted or appropriate.
24 Some decisions that were prudent may well turn out to be sub-optimal from a later
25 perspective. Others may, with similar hindsight turn out to be particularly
26 beneficial. I note also that the focus on reasonable judgment means that "prudence"

1 does not mean "perfection" but merely that the decision or actions could reasonably
2 have been made by competent decision-makers.

3 The relevant time frame for considering prudence, in this instance, is short.
4 Significant financial commitments to the units began only in 1999, and by no later
5 than early 2001, the decisions concerning construction of these units were
6 irrevocable, in that (1) no other timely resource was available to reliably meet load
7 on a timely basis and (2) construction expenditure was so far advanced that
8 cancellation was not an economic option. During that period, Pinnacle West:

- 9 • Could not reasonably have relied on the expectation that enough merchant
10 capacity would be built on a timely basis to meet APS load beginning in
11 January, 2003.
- 12 • Would not reasonably have anticipated the extent of the collapse of power
13 prices in the second half of 2001.
- 14 • Would not reasonably have anticipated that the ACC would unilaterally
15 modify the settlement and prevent PWEC's acquisition of APS's existing
16 assets.
- 17 • Would have recognized that no merchant capacity was being built to serve
18 APS's load, particularly to support reliability in the Valley load pocket.

19

20 **IV. THE PRUDENCE OF CONSTRUCTING THE RELIABILITY ASSETS**

21 **Q. Please summarize your conclusions concerning the prudence of constructing**
22 **the Red Hawk, West Phoenix and Saguaro units.**

1 A. Essentially, I reach two conclusions. First, the construction of the new units that
2 APS is seeking to include in ratebase was prudent. That is, the decision process
3 whereby APS's affiliates committed to the units was at all times reasonable, indeed
4 was quite appropriate even viewed with hindsight. Further, I demonstrate that the
5 cost of the units was reasonable in comparison to similar units constructed at about
6 the same time by others. My testimony demonstrates that it was prudent for
7 Pinnacle West to build the units in anticipation of the fulfillment of the Settlement
8 Agreement – either as part of a merchant portfolio eligible to compete to supply
9 APS's load or as units that would be dedicated to APS under an A.C.C.-approved
10 contract. I also demonstrate that Pinnacle West, acting as APS's parent, was
11 prudent in building sufficient resources to enable it to meet the substantial majority
12 of APS's load, notwithstanding the provisions of the Electric Competition Rules, in
13 view of the evolving circumstances that became inconsistent with the market
14 development expectations that the Electric Competition Rules and Settlement were
15 predicated upon. Indeed, in view of what was then known or knowable, it would
16 have been derelict for Pinnacle West not to have done so.

17 This leads me to my second point. The decision to build the units was
18 "APS-centric". While Pinnacle West was fully aware of the fact that generation
19 was to be severed from APS, and that the Settlement required that APS purchase its
20 energy and capacity from the competitive wholesale market, Pinnacle West used its
21 generation subsidiary to build or otherwise acquire the capacity that would be
22 needed to meet APS's load. The location of the Pinnacle West units, the integration
23 of them with new transmission to reach the rapidly growing Valley load center, the

1 acceleration of their commercial operation to match load growth forecasts for APS
2 and the deliberate decision to not contract the capacity on a long term basis to
3 California or Nevada all point to the fact that Pinnacle West's capacity expansion
4 plans were driven by APS's needs.

5 This does not mean that Pinnacle West proceeded without regard for the
6 provisions of the Electric Competition Rules. Indeed it was because of those rules
7 that it was compelled to act as it did, *i.e.*, to have necessary assets built outside of
8 APS. At relevant times, Pinnacle West had valid concerns as the owner of APS
9 that non-PWEC capacity would not be available on a timely basis, in sufficient
10 amounts, or at economic prices, to meet APS's load. Moreover, its studies
11 demonstrated that the PWEC portfolio, inclusive of transferred and new assets,
12 would have below market costs and would have been able to compete successfully
13 for as much of the APS portfolio requirement as it chose to serve in 2002 and
14 beyond. In fact, I have reviewed planning studies executed in 1999, the year that
15 West Phoenix and Redhawk were announced and initiated, that assumed, consistent
16 with the Settlement agreement, that all PWEC generation would be sold at no
17 higher than market prices, but also demonstrated that this low cost competitive
18 position would enable PWEC to be the successfully bidder for 100 percent of
19 APS's load requirements.

20 Because I will conclude that Pinnacle West had no prudent alternative to
21 building the capacity required to meet APS's load and all of the generation at issue
22 was built to serve that load, I have looked at the prudence issue in the same way
23 that I would have assessed prudence if APS still were a fully integrated utility and

1 had built the units itself. That is, rather than looking at prudence from the
2 perspective of PWEC building an integrated portfolio to serve the market, I have
3 looked at the resource planning decisions from the perspective of whether they
4 were a prudent basis for planning to meet APS's load. This is a more stringent test.

5 **Q. How have you examined the issue of whether construction of these assets was**
6 **prudent?**

7 A. I have focused primarily on planning decisions and studies in the late 1990s and the
8 2000-2001 period. This is the period during which the commitments to build the
9 PWEC generation were made. It encompasses also the period during which the
10 decisions theoretically might have been reversed based on what became known or
11 knowable after construction was initiated. I will refer to the prudence of decisions
12 to build the units as "planning prudence." As a separate matter, I also consider the
13 cost of these units in comparison to other similar units in order to determine
14 whether the units were prudently constructed. I will refer to the reasonableness of
15 the construction cost of the units as "construction prudence."

16 In assessing decisions to build the units, I have reviewed numerous planning
17 studies. Many if not all of the key studies that I will reference are discussed in Mr.
18 Bhatti's testimony. I also have relied on my own quite substantial knowledge of
19 what was happening in the electricity industry in the west and in the United States
20 generally during this period. To some degree, I also have relied on discussions that
21 I had with Pinnacle West planners and executives during this period.

22 **Q. How will you address the planning prudence issue?**

1 A. In considering whether it was prudent for APS to build these units, keeping track of
2 the chronology of events is critical. In the late 1990s, Pinnacle West found itself in
3 a unique position as a result of the ACC's Competition Rules and the Settlement.
4 On the one hand, APS (and hence Pinnacle West) had an obligation to serve the
5 needs of APS's full requirements customers reliably and economically. On the
6 other hand, APS itself was forbidden to acquire new generation.² Indeed, it was
7 anticipated that APS would, by the end of 2002, no longer control its then-existing
8 generation.

9 Had the situation evolved as anticipated at the time of the Competition
10 Rules in 1998 and 1999, this mismatch between APS's responsibilities and its
11 authority might not have been a problem. Prior to and into that period, APS
12 anticipated that there would be ample low cost power available in the West that it
13 could purchase on a short-term basis to meet its requirements through at least 2004.
14 Moreover, retail access was expected to result in a reduction in those requirements,
15 albeit by an unknown amount. Neither APS's forecasts, nor any other forecasts of
16 which I am aware, indicated a need to secure new capacity after 1998 prior to the
17 end of 2002 when the asset transfer was due to take place.³ Since new long term
18 capacity commitments were not believed to be needed before 2004 at the earliest,
19 even as late as the 1999 version of the Competition Rules, this may explain why
20 there was no provision in either the Electric Competition Rules or the Settlement
21 dealing with securing new supplies prior to 2003.

² During most of this period, it was assumed that the fossil generation would be transferred by the end of 2001 and the nuclear generation by the end of 2002.

1 More generally, the spirit of the Competition Rules was that the market
2 would provide. Certainly in 1998, and even in 1999, there appeared to be an
3 expectation by the ACC that the market would provide capacity sufficient to meet
4 APS's needs.

5 **Q. When did the expectation that APS would need no new resources before 2004**
6 **begin to erode?**

7 A. By about 1998 it became clear to APS that its load growth and growth for other
8 load serving entities in the Desert Southwest, and to a lesser extent growth in the
9 WECC generally, was very substantially exceeding expectations. This concern
10 deepened in 1999. As a result, future regional reserve margins that APS had
11 forecast to be ample until at least 2004 began to shrink rapidly. Moreover,
12 experience in states that were early adopters of retail access suggested that APS
13 would retain a need to serve substantially its entire load. Moreover, little new
14 capacity had been announced for Arizona and most of that appeared to be destined
15 for California. Despite AB1890, which in 1996 had restructured the California
16 market, attempts to build new capacity in that market were stalled by siting and
17 environmental permitting difficulties.⁴

³ For example, the 1999 WSCC 10-Year Plan still showed that the WSCC as a whole would be reserve adequate even under adverse hydro conditions through 2005 and the Desert Southwest region through 2004.

⁴ The California Energy Commission's database of new and planned generation in the WECC (http://www.energy.ca.gov/electricity/wscce_proposed_generation.html/download) shows only 59 MW of new generation (all of it geothermal) built in California in 2000, four years after AB1890. In 2001, about 2,600 MW of new generation came on line in the state, most of it after the crisis had passed and the majority of it being quickly built peaking units, many of which were commissioned as a result of actions by the state, the California ISO and California Department of Water Resources in response to the 2000-1 crisis.

1 Q. What issues did the acceleration of load growth and the slow development of
2 new merchant generation pose for APS and for Pinnacle West corporate
3 management?

4 The clearest issue that it posed was in the Valley. While the spirit of the
5 times was that APS would rely on the market (as were the California utilities), the
6 need in the Valley was quite specific and could not be met by an amorphous
7 reliance on market forces. Rather, it required that specific, real generating plants be
8 built in amounts and at a time sufficient to meet the Valley's requirement.

9 Under the terms of the Electric Competition Rules, APS was to meet its
10 needs from the market, including buying from PWEC (as contemplated and
11 specifically authorized by the settlement), at market prices. However, the market
12 was providing no new generation in the Valley. Reliability considerations required
13 that new generation be built within the Valley. Pinnacle West could compel only
14 one entity to build the generation – the corporate entity that would become PWEC.
15 Thus, in April 1999 Pinnacle West announced plans to construct West Phoenix 4
16 and 5. While peaking generation could meet the reliability needs of the Valley
17 area, analyses showed consistently that combined cycle units would be more cost
18 effective.

19 Q. Did the decision to build West Phoenix as a solution to the Valley reliability
20 problem fully solve the conundrum in which the Electric Competition Rules
21 placed APS?

22 A. No. The West Phoenix units were not sufficient to meet the overall energy and
23 reliability needs of APS. After observing the growth in peak loads in 1998, it was

1 clear that new capacity would be needed substantially earlier than had been
2 anticipated. New capacity would have to be secured to serve APS's load even if the
3 Valley reliability constraint was met by the West Phoenix units.

4 Merchant plants were not a demonstrated solution. By the end of 1998,
5 more than two years after AB1890 and Arizona's first restructuring order, only
6 three merchant units totaling approximately 1,600 MW had been announced in
7 Arizona. It should be emphasized that these were announcements only. Experience
8 shows that less than half of announced merchant projects (more typically, one-
9 third) actually are constructed in the general timeframe originally contemplated.
10 Moreover, two of the three projects were sited in northwest Arizona, off of APS's
11 transmission system, and clearly intended for the California/southern Nevada
12 markets.

13 APS's own studies indicated that California and southern Nevada would be
14 higher priced markets than Arizona and therefore more lucrative markets for
15 merchant generators to build in or sell into. Thus, it was not clear that the market
16 would provide sufficient capacity to meet APS's needs in the early part of the new
17 century. By the spring of 1998, APS's deficiency was projected to be
18 approximately 1,200 MW by 2002 and the decision to build West Phoenix would
19 cover only half of this.⁵ The 1998 system plan (which did not yet include West
20 Phoenix) still reflected a reliance on future market purchases to meet that need.
21 However, confidence that the market would continue to have a surplus sufficient to

⁵ The 1995 IRP showed a deficit of 200 MW in the year 2002. The 1997 Loads and Resources Forecast increased the 2002 load forecast by approximately 530 MW, implying a further generation need of

1 economically and reliably meet that need was eroding. The 1998 summer peak
2 turned out to be 400 MW above the then-current forecast; SRP had similar load
3 growth. This implied a further shortfall in the early-2000s, not merely for APS but
4 for the whole region. Partly for that reason, and partly to support its role under the
5 Settlement as an unregulated generator, Pinnacle West performed numerous
6 planning studies in 1998-1999 to consider options for meeting APS's load and
7 creating a balanced portfolio for PWEC.⁶

8 **Q. Do Pinnacle West's planning studies at that time indicate an unwillingness to**
9 **rely on the market for new capacity?**

10 **A.** No. As I stated, APS, as of early 1998, had determined that it remained prudent to
11 rely on the existing surplus of generation in the WECC to meet up to 1,000 MW of
12 APS's load requirements through 2004. For new generation, the assumption quite
13 properly was that the cost of power production for PWEC and the cost of new
14 wholesale contracts for APS would be essentially the same, whether PWEC or
15 some other vendor was the source. However, new generation, whether purchased
16 via contract or produced by PWEC, was not the preferred option. Pinnacle West's
17 preference was to buy available shares of existing Arizona baseload units rather
18 than to build new capacity itself. Its belief and expectation was that shares of these
19 units could be purchased at more economical prices than generation from new
20 units. Further, in view of the fact that all new generation for the foreseeable future
21 was expected to be gas, buying shares of existing coal and nuclear units was a

approximately 600 MW. The load forecast for 2002 increased by a further 400 MW in the Spring of 1998.
Note also that then-current plans were that West Phoenix 5 would be fifty percent owned by Calpine.

1 limited and disappearing chance to increase the non-gas share of generation
2 supporting APS's load. Owning coal and nuclear units would become increasingly
3 economic if Pinnacle West's expectation of higher gas prices was borne out.

4 **Q. Did Pinnacle West actively pursue buying additional shares of existing**
5 **generation?**

6 A. Yes. APS had negotiated an agreement to buy generation from TEP that was part
7 of the failed three-way settlement in 1998. In any event, the TEP purchase would
8 have carried with it a contractual requirement to serve TEP's load, so this would
9 have done nothing to cure APS's shortfall in the near term. Planning documents
10 indicate that APS considered buying LADWP's share of Palo Verde, but those
11 discussions went nowhere. Promising discussions were entered into with El Paso
12 Electric (El Paso) and Southern California Edison (SCE) concerning acquisition of
13 their shares of Palo Verde and Four Corners. It was believed that these plants
14 would allow Arizona load to be met through the early years of the new century.

15 **Q. Did Pinnacle West's planning presume that all potential purchases of shares in**
16 **existing jointly owned units could be used to meet APS's load?**

17 A. No. Planning studies indicate that any purchase from El Paso Electric would entail
18 a power buyback through at least 2004. Moreover, transmission limitations from
19 Four Corners meant that not all of SCE's share of that unit could serve APS's load,
20 even if SCE's transmission rights were purchased. Hence, at most 1,000 MW of

⁶ Until at least late 1999, these studies were performed by APS, since the Pinnacle West resource planning function at this time still was wholly within APS.

1 the purchases could be used to serve APS's load prior to expiration of any buy back
2 contract with El Paso.

3 Further, there never was any firm assurance that either of the purchases
4 would be executed, as indeed, they were not. The El Paso negotiations, in
5 particular, never even reached a Memorandum of Agreement stage. Moreover,
6 neither of the purchases would serve APS's need for in-Valley generation.
7 Redhawk and the purchases were simply elements of a portfolio of options that
8 Pinnacle West was pursuing to serve APS's load and provide a basis for off-system
9 energy sales by PWEC.

10 **Q. When did building the Redhawk units enter into Pinnacle West's planning?**

11 A. Studies conducted in 1998 indicated that it would be feasible to site up to 2,000
12 MW of gas-fired plant at or near Palo Verde. By early 1999 longer range
13 generation plans focused on building combined cycle plants at Palo Verde, totaling
14 up to 2,000 MW. Notably, building new capacity at Palo Verde was planned to
15 coincide with APS building additional transmission capacity into the Valley.
16 Hence, by design, all of this generation was capable of being used to serve APS
17 load. Similarly, in pursuing negotiations with SCE over its Four Corners share,
18 Pinnacle West also sought to acquire SCE's transmission rights that would enable
19 the acquired generation to be accessed by APS's load. Hence, both the construction
20 and purchase options were designed to enable the company to support APS's
21 requirements.

1 Q. Is there any particular point in time that you can identify when a critical
2 decision was made concerning Redhawk versus the attempt to purchase shares
3 of existing assets?

4 A. Yes. Expenditure on Redhawk began in the spring of 1999, albeit at a low level.
5 By autumn, Pinnacle West faced a decision concerning executing the engineering
6 and construction contract. Once that agreement was executed, the cost of
7 withdrawing from, or substantially delaying Redhawk would increase rapidly.

8 In parallel, Pinnacle West was negotiating with SCE and El Paso. While
9 the SCE Memorandum of Understanding was not executed until April 2000, and no
10 agreement ever was reached with El Paso, by that same time Pinnacle West had a
11 reasonably firm idea of what would be the agreed purchase prices.

12 Pinnacle West studies showed clearly that, at the expected prices, the SCE
13 and El Paso option was economically superior to the market – i.e. to the cost of new
14 combined cycle capacity, whether built by it or someone else. Hence in the fall of
15 1999 it faced a dilemma. On the one hand, it needed to “fish or cut bait” on
16 proceeding with immediate construction of Redhawk. This decision needed to be
17 made while it still was uncertain whether the SCE and El Paso negotiations would
18 ultimately prove successful. If the decision to go ahead with Redhawk was made,
19 and the negotiations with both parties proved successful, the corporation would be
20 substantially long in the market. Conversely, if Redhawk did not go ahead, and the
21 negotiations failed, APS load would be dangerously unhedged and potentially
22 unmet. This set of risks led to a major study dated September 11, 1999.

23 Q. Please describe the September 11, 1999 study.

1 A. There are several notable things about this study. First, it indicates that if all of
2 these plans came to fruition, Pinnacle West would be long in power markets.
3 Second, the study assumed that PWEC would serve 100 percent of APS load in that
4 sales equal to APS's load were assumed dedicated to APS throughout the study
5 period. Third, the base case for the study assumed, consistent with the facts as then
6 known, that relatively modest amounts of new generation would be built by
7 merchants in the relevant period. Both the Desert Southwest and California
8 remained short, California alarmingly so. Fourth, the study did an excellent job of
9 investigating the sensitivity of results to key drivers of the market. These included
10 gas prices, water levels for hydro generation, the amount of new builds, and the
11 possibility that major existing units for which closure was being discussed
12 (principally, the West Coast nuclear units and Mojave) would in fact be closed.

13 Based on study results, the acquisition of the shares of Palo Verde and Four
14 Corners was both the lowest cost action and provided the best hedge against rising
15 gas prices. Indeed, it was shown to be more cost-effective than Pinnacle West's
16 then-existing APS generation, primarily because it was believed that SCE's Palo
17 Verde share could be acquired at substantially below book value. The PWEC new
18 builds had forecasts costs essentially identical to the generation inherited from APS.

19 In short, the study showed that both main elements of the possible
20 expansion of generation were cost-effective against market alternatives and that the
21 fuel mix provided a useful hedge against known gas price uncertainty and potential
22 uncertainty concerning the future operating performance of nuclear and baseload
23 coal units.

1 Q. You stated that the Pinnacle West study assumed that PWEC would supply
2 100 percent of APS's needs. Wasn't that inconsistent with the Electric
3 Competition Rules?

4 A. No. The Competition Rules required that APS procure 100 percent of its
5 requirements from the market and the Settlement Agreement (which already had
6 been signed) specifically allowed sales to APS from an affiliate as "in the public
7 interest." It did not limit the amount that affiliated companies could sell to it at
8 prices no higher than the market price. At the time of the study, Pinnacle West
9 believed that the "all-in" cost of its fleet of generation taken as a whole (including
10 both purchases and new builds as well as the generation transferred from APS)
11 would be below the market price. It also believed that little if any generation local
12 to Arizona would be available to compete to serve APS's load, at least in the near
13 term. Finally, Pinnacle West management remained committed to meeting APS's
14 needs with resources that it controlled. The analysis I have been discussing
15 explicitly compared the cost of the PWEC fleet and its main components to the cost
16 of generation from a generic new combined cycle unit and concluded that the
17 PWEC fleet as a whole would have a significant cost advantage. Also, Pinnacle
18 West's studies showed that California would need to import more generation than it
19 believed would be built in the Desert Southwest or, equivalently would demand a
20 price higher than the price PWEC would need to receive in order to earn a capital
21 market-required rate of return on sales to APS. Hence, Pinnacle West's belief that

1 PWEC could profitably outbid such other suppliers as choose to compete to serve
2 the load was eminently reasonable and consistent with the Competition Rules.⁷

3 I should note that, in one sense, it did not matter that Pinnacle West
4 assumed that PWEC would serve APS's load. From an enterprise risk management
5 perspective, the key fact was that APS would in 2003 be more than 6,000 MW
6 short against the market since it no longer would own any resources. Thus, APS
7 was fully exposed, on both a price and reliability basis, to the market. While APS
8 needed to be hedged, its short position was essentially offset by PWEC's long
9 position. Viewed solely from the perspective of corporate-level economics, the
10 same potentially short market that would injure APS and its ratepayers would
11 benefit PWEC in essentially a like manner. The fact that Pinnacle West planned
12 and executed an expansion strategy geared to meeting APS's needs demonstrates
13 that its focus was on APS, not merely on the overall corporate bottom line.

14 **Q. So is it your testimony that Pinnacle West was comfortable being long against**
15 **the market by the approximately 2,000 MW that were shown in the study?**

16 **A.** No. First, I should note that Pinnacle West did not expect to have use of the output
17 from the El Paso units for some time, as there were commercial and regulatory
18 imperatives facing El Paso that meant that the power likely would not be available
19 to Pinnacle West until 2005. Also, in parallel to the analyses of potential expansion
20 of owned generation, Pinnacle West also was looking at partnering arrangements.

⁷ I use the term "profitable" here as it is used by economists, not in its accounting sense. Economic profitability is profits in excess of full costs, including a return on the equity portion of capital, whereas an asset is profitable in the accounting sense if it makes any equity profit at all. Note too that while sales at below-market prices could be profitable in this sense, they still were not profit-maximizing since selling at market prices would be still more profitable.

1 My recollection is that there were three reasons for such negotiations. First,
2 it intended to use the joint ventures to enhance its skills in carrying out the planned
3 expansion. Pinnacle West sought a joint venture relationship with Calpine because
4 Calpine was a large scale and highly reputable power project developer. It sought a
5 relationship with Reliant because Reliant was a highly experienced marketer of
6 both electricity and gas. Pinnacle West thus sought to partner with entities that
7 brought skills to the bargain that complemented and supplement Pinnacle West's
8 abilities.

9 Second, Pinnacle West sought to reduce its long position, notwithstanding
10 that it appeared from its studies that a long position would be profitable. The
11 Calpine and Reliant ventures involved partnering arrangements that, effectively,
12 divested half of Redhawk 1 and 2 and half of West Phoenix 5, a total of nearly 800
13 MW.⁸ This substantially reduced the potential long position, particularly for the
14 first several years. I should note that part of the Reliant deal was a swap. However,
15 the swap was less than megawatt-for-megawatt and diversified market exposure
16 within the WSCC.⁹

17 Third, there was no assurance that both or either of the SCE and El Paso
18 negotiations would succeed. The failure of either would substantially eliminate the
19 long position. Pinnacle West's "supply plan" as of the fall of 1999 can best be
20 thought of as a group of options that were being pursued to ensure that APS needs

⁸ Note that the fact of the joint ventures did not limit the output from the Redhawk and West Phoenix units that could be made available to APS. However, Calpine and Reliant were under no obligation to offer their output to APS.

1 still could be met even if some of them failed to be feasible or if circumstances
2 differed materially from plan. Redhawk was the "fly wheel;" timing of it was being
3 managed to compensate for, and balance, changes in the more favored program of
4 purchasing shares of existing generation.¹⁰

5 **Q. Please continue through your time sequence. What happened subsequent to**
6 **September 1999?**

7 A. In the fall of 1999, Pinnacle West signed the EPC agreement for Redhawk and
8 announced it to the public. I hesitate to say that this was now a "committed"
9 investment since for an increasingly steep price it could be unwound. For example,
10 by the end of 1999, cancellation costs had risen to approximately \$200 million.

11 An agreement in principle to buy SCE's share of Four Corners and Palo
12 Verde was entered into in April of 2000. By this time, the negotiations to purchase
13 El Paso generation had failed to produce a positive result. Under the SCE
14 agreement, SCE had an opportunity to "shop" the bid to other buyer, so the
15 purchase remained uncertain.

16 As the California crisis began in early May 2000 and continued through the
17 summer (and beyond), Pinnacle West came to regard the SCE purchase as
18 increasingly unlikely. First, as forward prices rose, the likelihood that an
19 alternative buyer would emerge who would outbid the MOU price by an amount

⁹ By the time that the joint venture arrangements were terminated in early 2001, APS needed the capacity that was released. Moreover, eliminating the swap deal with Reliant better focused the geographic position of the PWEC assets on APS.

¹⁰ For example, a planning study early in 1999 provided for building one Redhawk unit per year starting in 2002 if the purchase of SCE's shares did not occur, but delaying the schedule by two years if it did. A one-year delay also was modeled. At the time of announcement in fall, 1999, the schedule was to build the first unit in 2003 and the second in 2004.

1 that Pinnacle West would not match increased substantially. Pinnacle West's
2 attitude toward acquisitions that were not clearly tied to APS's load was cautious as
3 a general matter, as demonstrated by its hesitant posture toward purchasing the
4 California fossil assets divested by that state's IOUs, and it was unlikely that they
5 would outbid the most optimistic alternative bidder in a suddenly bullish market for
6 the SCE assets. Second, as the California utilities, including SCE, piled up billions
7 of dollars in unrecovered power costs as a result of being under-hedged, it became
8 increasingly likely either that SCE itself would end the sale or that the California
9 government and regulators would not permit still further divestiture that would
10 remove the (inadequate) hedge against the short term market that SCE still retained.
11 Hence, the SCE deal at the desirable negotiated price became increasingly
12 speculative.

13 Ultimately, the SCE's Four Corners share was bid away from Pinnacle
14 West.¹¹ The agreement to buy the share of Palo Verde survived on paper until the
15 beginning of 2001, when the California legislature forbade California utilities from
16 selling any of their generation.

17 **Q. Moving beyond the events of September 1999, please take up again your**
18 **chronology of what was happening with the Pinnacle West companies.**

19 **A. During 1999, the negotiation and ultimate acceptance of the Settlement meant that,**
20 **by the end of 2002, APS's existing generating assets would be consolidated into**

¹¹ While SCE did not formally inform Pinnacle West that its bid had been topped (by a quite substantial margin) until nearly the end of 2000, it earlier had signaled that superior offers were being negotiated. Well before the end of 2000, Pinnacle West had resigned itself to the likelihood of such an event. In any event, the matter was moot since it was by then highly likely that California would not permit the asset sale to take place, as was soon thereafter confirmed by legislative action.

1 PWEC. Studies were performed to determine whether the combined assets,
2 including both the assets to be purchased from SCE and new gas-fired generation at
3 West Phoenix and Palo Verde, would be competitive at market prices. It was
4 determined that they would be. In part this was due to the lower costs of the
5 existing assets and the SCE assets relative to new combined cycle units.

6 In the fall of 1999, Pinnacle West announced the Redhawk project with
7 units 1 and 2 planned to come into service in 2003 and 2004. The last four months
8 of 1999 saw several other new plant announcements by other generators. Again,
9 there was no assurance that all, or indeed any, of these units would be built (indeed,
10 it was quite unlikely, based on historic experience) or even if built would be made
11 available to meet APS's load. None of the merchant units began construction until
12 the late winter of 2000-2001, well into the Western electricity crisis. Significantly,
13 none of the new merchant units (i.e., other than SRP units) were sited to meet
14 Valley reliability requirements.

15 The sudden rush of plant announcements in late 1999, before the run-up of
16 prices in Spring, 2000 demonstrates that Pinnacle West was not alone in forecasting
17 that power supplies in the WECC would soon become very tight. No similar spate
18 of announcements was seen in California, the most power deficient region,
19 however. A major contributing factor to the geographic distribution of new
20 announcements doubtless was the continuing inability to site plant in California. In
21 contrast, Arizona presented a relatively efficient and feasible permitting process.
22 With substantial transmission available between Arizona and California, these

1 plants (most of which were clustered around the strong Palo Verde hub) would
2 have opportunities to trade into, and transmit power to, California.

3 **Q. What happened in 2000?**

4 A. Moving into 2000, none of the new facilities announced in 1999, except for West
5 Phoenix 4 and Redhawk, actually began construction until 2001. With relatively
6 little invested in these new facilities, a shakeout reasonably could be anticipated.

7 Pinnacle West perhaps could have cancelled Redhawk during a narrow
8 window after the first of these new projects were announced and before it signed
9 the Redhawk EPC contract if it believed that APS could secure power from one or
10 more of the merchant generators on at least as favorable of terms and with the same
11 degree of assurance that the power would be available on a timely basis. But other
12 than the three units that had been announced in 1998, none of the Arizona merchant
13 plants actually began construction before the spring of 2001. Moreover, there was
14 no reason to assume that the cost of a contract for the output of a new combined
15 cycle unit owned by some other generator would be lower than the cost of a
16 contract with PWEC for power from Redhawk; a merchant unit would not be built
17 to serve a long-term contract at less than full cost. Moreover, under the Settlement,
18 there was no provision for APS to enter into such a contract and, even were it to
19 enter into it, there was no assurance that it could retain the contract rather than
20 divest it to PWEC by the end of 2002, since the Electric Competition Rules had
21 defined "generation" to include such contracts.

22 **Q. Did the Western U. S. energy crisis affect Pinnacle West's options?**

1 A. Yes. Beginning in May of 2000 prices exploded in the WECC and remained quite
2 elevated into the summer of 2001. Forward prices also were elevated, reflecting
3 both views of gas prices and an acknowledgement that power could well be in short
4 supply, leading to shortage pricing, for a prolonged period. During this period,
5 long-term contract prices moved to at least the full cost of new generating plant.
6 An example is the contracts entered into by the California Department of Water
7 Resources (CDWR) in the winter of 2000-1. As has been widely reported, the
8 average cost of these contracts, totaling in excess of 10,000 MW, was \$69/MWh.
9 By no later than the second half of 2000, APS could not have signed a long term
10 contract for power for a cost as low as the construction cost of its new units, even
11 setting aside the fact that the units were partly built and much of their cost was
12 "sunk."

13 In mid-2000, Redhawk 1 and 2 construction was accelerated to come on
14 line by summer of 2002. This provided a reliability and energy cost backstop in
15 case the SCE purchases could not be made. This became increasingly likely as the
16 crisis continued and the cost to California of its load being substantially unhedged
17 mounted. In addition, steps were initiated to bring back capacity APS's mothballed
18 capacity, and for PWEC to install temporary capacity, to meet APS's load in 2001.
19 West Phoenix 4 also was a critical element of the plan to meet 2001 load.

20 Q. You mentioned the CDWR long-term contracts. Why didn't Pinnacle West
21 sell long-term contract power to CDWR?

22 A. By January and February of 2001, when the contracts were solicited, Pinnacle West
23 was no longer long. The planned purchase of SCE capacity had gone away and the

1 company no longer had enough planned resources to meet APS's load. The effect
2 of the loss of the SCE purchase on its supply-demand balance was, in part,
3 compensated by the termination of partnering arrangements with Reliant and
4 Calpine. Nonetheless, Pinnacle West's total existing and planned resources were
5 less than APS's requirements in each year from 2001 and thereafter.

6 Of course, had PWEC been a stand-alone unregulated market generator, it
7 likely would have viewed the situation quite differently. PWEC had generation
8 coming on line beginning in the summer of 2001 and would be hugely long when it
9 would acquire the APS generation in late 2002. It was far better positioned than
10 many sellers who sold to CDWR to back up a contract with real assets over most of
11 the contract period. Notably, however, Pinnacle West's corporate management
12 chose to override PWEC's commercial interest and declined to offer a long-term
13 contract to CDWR. It was clear that APS would need capacity from market sellers
14 in amounts that would increase megawatt-for-megawatt by the amount that PWEC
15 would sell. Either APS or some affiliate would need to buy replacement power
16 from a market that (based on forward price offers) would be far more expensive
17 than Pinnacle West's existing or new resources.

18 **Q. How did Pinnacle West factor the new Arizona merchant generation into its**
19 **plans?**

20 **A.** As new units were announced in late 1999 and in 2000, most of them combined
21 cycle units, it became increasingly likely that the Western U.S. would have a
22 surplus of energy (MWH) even if summer capacity margins (MW) remained
23 relatively tight. Pinnacle West's planners began looking at changes in its resource

1 plan that would make it less energy long and/or better able to take advantage of
2 anticipated lower cost off-peak markets. In particular they began to reassess the
3 schedule for Redhawk 3 and 4. This reflected Pinnacle West's increased
4 willingness to be slightly short against the market in those years for which
5 modification of its resource balance still was an option. The 2001 system plan
6 showed that corporate resources would be short relative to APS's requirements by
7 about 350 MW in 2003-5. This reflected an anticipation, also shown in its market
8 price forecasts, that the market would cool in the face of new construction and
9 resurgent reserves.

10 These market expectations could not, however, materially impact West
11 Phoenix and Redhawk 1 and 2. West Phoenix remained necessary to meet load in
12 the Valley. The first two Redhawk units were heavily committed; too much of their
13 costs were sunk for cancellation to be cost-effective even if prices turned out to be
14 well below forecasts made in 2000-2001. Thus, by the time prices softened in 2001
15 and it became more likely that at least some of the Arizona merchant plants would
16 be built and not fully committed to California and thus would be available to serve
17 Arizona loads, canceling either West Phoenix or Redhawk 1 or 2 was not an option.
18 Indeed, as early as November 2000, when construction started, over \$500 million
19 had been contractually committed to Redhawk construction.

20 **Q. You several times have mentioned Pinnacle West's continued reliance on the**
21 **terms of the Settlement during this period. Should Pinnacle West and APS**
22 **management have anticipated that the Settlement would be modified?**

1 A. No. The ACC had given no indication that it would seek to unilaterally modify the
2 terms of the Settlement. Nor did Pinnacle West and APS take any action likely to
3 cause the ACC to do so. As I have discussed, management throughout this period
4 was concerned with protecting APS and its customers, even at the expense of
5 PWEC profits.

6 Nevertheless, in the spring of 2001, management began to consider the
7 effect of APS buying 100 percent of its requirements from the market. This was
8 motivated both by its concern for APS's customers and a concern for APS's
9 financial integrity. APS, like SCE and PG&E who were fully or nearly bankrupted
10 by having to buy the majority of their power from the market, was subject to a rate
11 freeze. If APS were required to buy all of its needs from the market, then it would
12 be trapped between high market prices and a fixed (indeed, declining) retail tariff,
13 precisely as had occurred in California in 2000.

14 In part also, the analysis was driven by uncertainty about how regulation in
15 Arizona might change. California had, by then, cancelled the planned sales of
16 generation by both SCE and PG&E and, generally, was seeking to role back both
17 retail access and dependence on competitive markets. Nevada also had put the
18 brakes on its restructuring plans, including the sale of Nevada Power's owned
19 generation. Several other states, primarily in the West and nearby areas in the
20 southern mid-west, also had frozen or abandoned restructuring. While APS and its
21 customers were largely unaffected by the western power crisis, unlike California
22 and Nevada, and the ACC had shown a much stronger commitment to restructuring
23 than some other states that halted steps to restructure, it was viewed as quite

1 possible that the ACC would seek or even require arrangements that would assure
2 that APS would be protected from what was then an out-of-control market.

3 As a consequence of these concerns, Pinnacle West analyzed three cases
4 that included the required transfer of APS's generating assets to PWEC with APS
5 relying fully on the competitive market and two versions of re-integration of APS
6 with the Pinnacle West generating assets. One such case provided that the assets
7 being constructed by PWEC would be transferred to APS on a book cost basis. The
8 other assumed that the APS assets would be transferred to PWEC as agreed, but a
9 long-term contract, essentially at cost of service, would be signed between APS and
10 PWEC.¹² Either of these re-integration scenarios assumed that the requirement that
11 APS buy from the market as envisioned by the Electric Competition Rules would
12 be waived or terminated.

13 Using its April 2001 price forecasts, it was found that the cost of meeting
14 APS's load would be higher under the full market reliance scenario called for in the
15 Electric Competition Rules than under the options that retained the APS and PWEC
16 assets for system use, either via contract or re-regulation. In particular, the
17 expected cost of meeting APS's load in 2002 and 2003 under the terms of the
18 Settlement was considered likely to cause severe financial difficulty to APS as a
19 result of the rate freeze. From a Pinnacle West-wide enterprise perspective this was
20 not a first order, direct bottom-line profit issue, since losses at APS occasioned by
21 having to buy at market prices would be counterbalanced by high profits at PWEC

¹² A fourth case in which only the existing APS assets were retained was originally specified but determined to be so impractical and unlikely that the analysis of it was never completed.

1 if it also transacted at market prices. However, true exposure of APS to the
2 expected market would have impacted its financial integrity, adversely affected its
3 bond ratings and likely would have led to a request for emergency rate relief, as
4 was permitted under the Settlement.

5 As the market cooled in late spring, near-term price forecasts declined
6 sharply. However, the long-term forecast worsened. From an APS customer
7 perspective, the situation actually worsened since lower prices during the rate freeze
8 were counter-balanced by higher prices post-freeze. Reanalysis of the three cases
9 with these later (June 2001) forecasts reaffirmed that the status quo full market
10 reliance scenario still was higher cost to APS and its customers than either of the
11 reintegration scenarios.

12 Based on these results and other considerations, Pinnacle West determined
13 that its preferred course of action would be to propose to reintegrate via a long-term
14 contract with PWEC. While the decision that reintegration would be its preferred
15 option was made in the late Spring of 2001, it took considerable time for APS and
16 PWEC to agree on the specific terms of the contract, which delayed filing of the
17 proposed PPA and request for a variance from the competition rules with the ACC
18 until later in the year.

19 What is significant about Pinnacle West's choice to reintegrate by contract
20 in the Spring of 2001 is that, based on then-expected prices, this was not the most
21 profitable course of action for Pinnacle West. The PPA would yield significantly
22 lower revenues to PWEC than would expected market prices. Consumers would
23 have been shielded from these market prices (and APS correspondingly exposed),

1 but only until the rate freeze ended, which was well before the earliest termination
2 date for the PPA. Thereafter, it was expected, based on then-forward price
3 forecasts, that customers would pay higher prices absent the PPA. Hence from an
4 overall corporate profitability perspective, the contract was a non-event until the
5 rate freeze expired in 2004, but subsequently less profitable to the corporation than
6 the "status quo" -- the arrangements under the Settlement -- thereafter.

7 **Q. What do you conclude from this review of resource studies and business**
8 **decisions over the period through 2001?**

9 A. First, from a Pinnacle West corporate point of view, the decision to build the West
10 Phoenix and Redhawk units was prudent in terms of its responsibility for meeting
11 APS's customers' needs. The same decision would have been prudent if a) APS
12 had remained integrated; b) PWEC were a stand-alone merchant generator owning
13 these assets along with the existing APS assets, or c) Pinnacle West, as the parent of
14 both companies, was the guarantor that APS load would be met reliably and
15 economically, as was the case in any event. Based both on my current review of
16 the Pinnacle West planning studies and decisions, and my reviews of studies and
17 discussion at the time, Pinnacle West's corporate strategy was dominated by its
18 concern with protecting APS's customers and APS's financial integrity. As the
19 PPA offer in 2001 would demonstrate, Pinnacle West was prepared to sacrifice
20 significant enterprise profits in order to protect the customers that APS had served
21 for nearly a century, as well as the utility itself.

22

23

1 **V. REVIEW OF APS SYSTEM PLANNING IN 1998-2001**

2 **Q. What do you conclude as a result of your review of Pinnacle West's planning**
3 **activities?**

4 A. The resource planning analysis and related management decisions were of high
5 quality. The resource planners engaged in numerous and frequent studies of
6 southwestern and western power markets. They performed numerous scenario
7 analyses and sensitivity studies. Planners used state of the art models. They also
8 closely monitored new construction, both in Arizona and throughout the west.

9 As I stated in my summary, I have reviewed numerous planning studies in
10 preparation for this testimony and, in many cases, contemporaneously. The quality,
11 frequency and diversity of these studies are state of the art. The company's
12 planning personnel are highly experienced, skilled and knowledgeable. Databases
13 were carefully prepared and models of the highest quality were employed. The
14 corporate culture allowed planners to reach technical and economic judgments
15 based on their analyses and expertise, rather than to ratify pre-determined corporate
16 policies and strategies. I know from my own experience that at key points outside
17 independent experts were brought in to review the analyses and resultant
18 recommendations.

19 As I have just discussed, Pinnacle West's planning and decision making
20 was "APS-centric." However, it also recognized that Pinnacle West – both its
21 generation arm and APS – would be participating in the western power market and
22 its planning and decision-making was informed by monitoring and analyzing the
23 entire western market, in terms of supply and demand balances and prices.

1 Pinnacle West showed no bias toward construction. If anything, its
2 preference was to rely as much as is prudent on competitive markets, taking
3 advantage of anticipated low prices, and to buy existing resources rather than build
4 new ones. Its recognition that partners brought complementary abilities and its
5 desire to spread plant-specific risks was illustrated by efforts to engage in joint
6 ventures with experienced developers and marketers.

7 A hallmark of Pinnacle West's resource planning decisions was their
8 flexibility. Initially, the company focused primarily on supplemental economy
9 market purchases. As load grew, it responded by, first, building new facilities to
10 meet the needs of the Valley load pocket and by seeking to buy existing facilities
11 while backstopping the risk that purchases would not materialize with a flexibly
12 scheduled Redhawk. As it became clear that the short-term market was a
13 dangerous place to be, and that the shares of existing resources would not be
14 available, Pinnacle West moved up the schedule for Redhawk.

15 During the western energy crisis, Pinnacle West's planning deserves
16 particularly high marks. During my long association with the planning group, they
17 always have been focused on market fundamentals. This fundamental view led
18 them to forecast that the worst of the immediate crisis would be of relatively short
19 duration. Unlike other load serving entities in the West, Pinnacle West did not
20 engage in panic buying of long-term power during the heart of the crisis. Of
21 course, Pinnacle West could afford to be more sanguine than others, since the
22 retention of existing generation and the ownership of the new PWEC assets meant

1 that, at least on an energy basis, the company was unlikely to be a net buyer in the
2 market.

3

4 **VI. CONSTRUCTION PRUDENCE**

5 **Q. Turning to the prudence of the construction of the PWEC Arizona generation,**
6 **as distinct from the decision to build the units, how is construction prudence**
7 **addressed?**

8 **A.** In some cases, this is done by a detailed audit of construction management and the
9 costs of construction. A simpler method is to first benchmark the cost of
10 construction. If the construction cost of a unit is within the general range of the
11 cost of other such plants, the presumption of prudence is upheld and there is no
12 need for the type of detailed and expensive audit that was performed for the Palo
13 Verde nuclear plant.

14 **Q. Have you undertaken such a benchmarking study?**

15 **A.** Yes, within the limits of what is achievable. Unlike previous periods in which the
16 cost of new units was apparent from FERC Form 1 data, cost data are not now
17 uniformly available.

18 **Q. What data have you used for benchmarking?**

19 **A.** I have utilized two data sets. The first is the RDI NewGen database. Specifically, I
20 culled data on all combined cycle units coming on line in 2001 through early 2003.
21 The second source is the California Energy Commission's database on new
22 generation in the WECC. From this database, I extracted data on all completed
23 combined cycle units that either have come on line or are under construction with a

1 near term planned completion without a major deferral in on-line date (i.e. without
2 a construction stoppage).

3 **Q. Are these databases comprehensive?**

4 A. No. Each database contains many units for which no construction cost estimate is
5 present. Somewhat surprisingly, there is very little overlap in the two databases.
6 That is, most of the units for which cost data are contained in the CEC database
7 have no cost data in the RDI database, and conversely. There is no reason to
8 believe that the incompleteness of data biases the sample for which cost estimates
9 are available.

10 **Q. How confident are you of the cost data contained in these two sources?**

11 A. The cost data likely are broadly representative, but are known to be biased
12 downward.

13 **Q. How do you know that the cost estimates are biased downward?**

14 A. I know because for some of the units I have confidential cost information from
15 other sources that shows significantly higher costs than are reported in these
16 databases. Also, I know how these data are collected, and why it is that these
17 sources will cause the data to be biased.

18 **Q. Please explain the source of the bias.**

19 A. The cost information comes from public announcements by the owners. However,
20 costs as announced often exclude certain cost elements and often are early, design
21 cost estimates that exclude cost growth as the project contracts are let and design is
22 completed. Moreover, some projects overrun because they encounter construction
23 problems or equipment failures. The types of cost that may be excluded include

1 interest during construction and other owner's costs, transmission-related costs and
2 spare parts. The growth of cost from initial design estimates is exemplified by
3 Pinnacle West's units. For example, as discussed by Mr. Bhatti, West Phoenix 4
4 was initially forecast to cost \$60 million and ultimately cost \$78 million Redhawk
5 was initially forecast to cost \$250 million per unit and ultimately cost \$286 million
6 per unit. West Phoenix 5 initially was forecast as \$251 million and is now forecast
7 to cost \$289 million.

8 **Q. How do you know that the databases include these types of original cost**
9 **estimates as opposed to final costs?**

10 A. Both the RDI database and the CEC database include West Phoenix 4 and each
11 shows a cost of \$60 million. The CEC database includes Redhawk 1 and 2 at a cost
12 of \$250 million per unit, and West Phoenix 5 at \$255 million. Also, I have an older
13 version of the CEC database dating back to 2001. I checked it and found that the
14 same cost data are contained in it as are contained in the current CEC database.
15 Thus, while entries in the database indicate that data have been updated in the
16 interim, apparently, the update does not include updated costs.

17 **Q. In view of these biases, why have you used these data for benchmarking the**
18 **Pinnacle West units?**

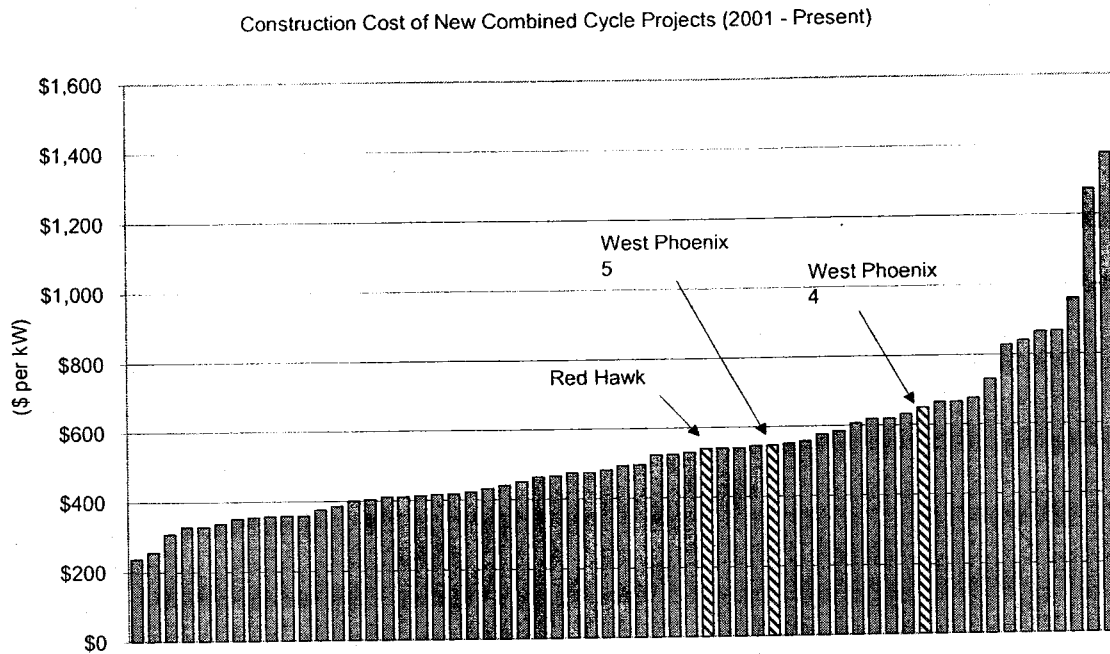
19 A. Flawed though they are, they are the only data on which I am aware. If the
20 Pinnacle West plant costs are within the general range of these downward biased
21 data, then the costs of the plants clearly was reasonable.

22 **Q. What does the RDI database show to be the cost of new combined cycle units?**

1 A. The simple average cost is \$535/kW with a range of \$413/kW to \$1375/kW. I am
2 inclined to distrust both of the extremes. Figure WHH-1 shows the data
3 graphically, with the Pinnacle West units included. The Pinnacle West units are
4 well within the pack, notwithstanding the data biases I have described. I should
5 also note that units coming on line earlier tend to have lower costs and that smaller
6 units tend to be more expensive on a per-kW basis.

1

Figure 1



2

3 Q. What do the CEC data show?

4 A. The CEC data average \$578/kW with a range of \$383/kW to \$954/kW. Again, I
5 distrust the extremes, but the average again indicates that the cost of the APS units
6 (approximately \$550 per kW) was reasonable. Note also that if, as I have indicated,
7 the data in these databases consists primarily of initial estimates, the comparison
8 properly is to the initial estimates for the Pinnacle West combined cycle units.
9 These total to \$474/kW for the four units.

10 Q. Do the CEC data give any guidance on the cost of the Saguaro peaking unit?

11 A. The database includes cost data for a few units. They range from \$417/kW to
12 \$1000/kW. At \$500/kW, the Saguaro unit is toward the bottom of the range. The

1 final cost of the Saguaro unit was slightly under the design budget and hence is
2 lower still.

3 **Q. What do you conclude from this benchmarking?**

4 A. The cost of the Pinnacle West units clearly is within a reasonable range as
5 demonstrated by this comparison. If one takes into account the biases in the
6 databases, Pinnacle West's combined cycle units were built at a cost below the
7 average for comparable units. Its simple cycle Saguaro units also benchmarks
8 favorably. Hence, I conclude that these units were built at reasonable costs, from
9 which I infer that their construction was prudently managed and executed.

10

11 **VII. THE PWEC ASSETS ARE USED AND USEFUL**

12 **Q. Please define the term "used and useful" as it normally is used in electricity**
13 **regulation.**

14 A. In its origins, the term is equivalent to "used in utility service". The concept was
15 that investments and expenses that were not related to serving customers should not
16 be recovered in rates. For example, Pinnacle West's investment in Suncor, a real
17 estate venture, is not recoverable in rates.

18 **Q. How is the "used and useful" test typically conducted for electric utility**
19 **generation?**

20 A. The used and useful test has been applied to generating plants primarily in the rate
21 cases in which the utility was seeking to ratebase a new unit. Almost invariably, the
22 used and useful test was conducted by comparing the total megawatts of the
23 utility's capacity with its load requirement. In some cases, a unit was used and

1 useful if any part of it was needed to meet the strict standard of load plus reserves.
2 In other cases, plant was subject to exclusion on a megawatt-by-megawatt basis if
3 not needed. In still other cases, costs were disallowed only if no part of the plant
4 would be needed within some reasonable period of time. In some cases, any
5 disallowance was not specific to the new unit.

6 **Q. How does the used and useful standard differ from the prudence standard?**

7 A. As described previously, the prudence standard looks at whether decisions were
8 reasonable at the time that they were made, considering what was known or
9 reasonable knowable at the time. This is a "no hindsight" test that does not depend
10 on ultimate outcomes. Conversely, used and useful looks at an ultimate outcome,
11 whether in fact the unit was needed to meet load, given what load turned out to be
12 when the owner sought to put it into ratebase. Because load growth is inherently
13 uncertain, this test is less "fair" than the prudence test, unless it is applied
14 reasonably – i.e. to allow a reasonable margin for forecast uncertainty and the
15 lumpiness of economic plant additions.

16 **Q. Is there a potential inconsistency between the prudence standard and used and**
17 **useful and, if so, how should that inconsistency be resolved?**

18 A. Yes, there is a potential inconsistency. The prudence standard is inherently forward
19 looking from the perspective of what was known or knowable when decisions were
20 made. In most instances, prudence would subsume the issue of whether the plant
21 reasonably was believed to be used and useful, once completed, at that time. The
22 used and useful test, as generally practiced, compares resources to needs as
23 anticipated at the time of the ratecase, i.e., with the benefit of hindsight concerning

1 actual rather than unanticipated load growth. In extreme cases, even a "fair" used
2 and useful test could be failed, in whole or in part, with respect to a prudently
3 planned and constructed plant.

4 For this reason, the proper course is to give primacy to the prudence
5 standard. Fortunately, in this case the issue of which standard should dominate
6 need not be faced since the investment is both prudent and used and useful.

7 **Q. Are the PWEC assets that APS is seeking to ratebase used and useful?**

8 **A.** Yes. West Phoenix 4 has been used and useful beginning in the summer of 2001.
9 Saguaro and Redhawk have been used and useful since the summer of 2002. West
10 Phoenix 5 will be used and useful when it comes into service this summer. When I
11 state that they are used and useful, I mean that they are needed to meet reliability
12 and that they also are used to meet native load.

13 While it is the case that these assets already are used and useful, the actual
14 application of the test, in Arizona and elsewhere, is related to the period beginning
15 when rates go into effect. When the rates set in this case go into effect, most likely
16 no earlier than sometime in the latter half of 2004, APS's load during the peak
17 season will be met in substantial part by these assets that are under contract to serve
18 that load. Notwithstanding this contract, and other contracts signed during Track B,
19 APS is projected to be short of capacity by 2004 and increasingly short in every
20 year thereafter. Moreover, the bulk of the capacity that APS has under contract as a
21 result of Track B is the PWEC Arizona capacity.

22

1 **VIII. LESSONS FROM THE TRACK B PROCUREMENT**

2

3 **Q. What can be learned from the Track B procurement?**

4 **A.** First, with the exception of PWEC, suppliers generally were unwilling to enter into
5 contracts at below the expected spot prices for the contract period. A few offers
6 were slightly in the money, based on APS's forward price curves. These slight
7 discounts likely reflect that some sellers had a slightly lower forward price curve
8 than did APS, rather than a willingness to sell below the forward market. This
9 result should come as no surprise: a profit maximizing seller will not deliberately
10 sell via contract for less than it can get in other sales venues.

11 Second, a substantial part of the non-PWEC Arizona merchant generation
12 was not offered at all. In addition to the 150 MW from Sundance that APS
13 accepted, only 1512 MW were offered.¹³ In addition, approximately 630 MW was
14 offered by power marketers, at least some of which may have been backed by
15 Arizona generation. Nothing was offered by several large generation owners such
16 as Duke and Sempra, nor from load serving entities, such as SRP, WAPA or
17 AEPCO. In addition, not all of this bid power was deliverable because the bidders
18 selected transmission paths that could not simultaneously accommodate all of the
19 bid amounts. APS estimates that the total amount of non-PWEC generation that
20 could have been delivered if PWEC used none of the constrained interfaces would
21 have been 1,463 MW in 2004 and lesser amounts in other years. Had PWEC not
22 bid, and made the offers that it did, APS would have received very little power

¹³ Cited totals are for 2004, the peak year of offers.

1 priced at or below its forward price curve. It would have been able to contract for
2 only a fraction of its needs, about half, at any price.

3 Third, there was very little non-PWEC capacity offered on a long-term
4 basis. APS was offered 225 MW of peaking capacity and 300 MW of combined
5 cycle capacity (from a unit that has not begun construction or even received a
6 Certificate of Environmental Compatibility) beginning in 2006. Both of these
7 offers were out of the money. It also received a very small intermediate term (five-
8 year) non-asset-backed offer from a power marketer.

9 The absence of long-term offers suggests that potential sellers view the
10 post-2005 market with greater optimism than is reflected in current forward
11 markets. To the extent that their capacity is not already committed to other buyers,
12 sellers apparently prefer to accept the risks of selling short term for the next year or
13 two in order to preserve the value of having capacity to sell at market in later
14 periods.

15 The paucity of offers at a time when prices in the market are so depressed
16 that sellers are going bankrupt speaks volumes about the folly of requiring that APS
17 commit to replace the contracts and buy needed new supply to meet load growth
18 from the market when its current Track B contracts expire at the end of 2006. As
19 discussed below, the current glut of capacity likely will have fully disappeared by
20 about that time. At best, APS would have to compete head-to-head against
21 California for the Arizona merchant capacity. The ACC cannot reasonably expect
22 that PWEC, having twice been denied a long-term sale of its output (by contract or
23 outright) would continue to withhold its capacity from the export contract market.

1 Nor can it rely on other generators having held back thousands of megawatts of
2 capacity on the mere hope that APS will be compelled to pay higher prices than in
3 nearby markets.

4 **Q. What do you conclude based on your review of the Track B solicitation?**

5 A. Even at the peak of the glut in Western power markets, there was not nearly enough
6 non-PWEC capacity offered to meet APS's needs. APS will be significantly
7 shorter by the time that the Track B contracts expire. There is no evidence that
8 additional capacity will be built in Arizona. In particular, there is no evidence that
9 in-Valley capacity will be built. The Western power market, overall, is virtually
10 certain to be much tighter and market prices to be higher. A new solicitation held
11 in 2006 would be unlikely to yield the capacity that APS will need at prices as
12 attractive as the ratebase cost of the PWEC units and might not yield the needed
13 capacity at all.

14 .

15 **IX. OBSERVATIONS ON FUTURE WHOLESALE MARKET PRICES**

16 **Q. Can you determine at this time whether the PWEC Arizona assets are cost-**
17 **effective relative to the wholesale market?**

18 A. Let me preface my answer by noting that this question should not be relevant to
19 ratebasing these assets since, in view of the facts, the prudent investment test is the
20 relevant standard. This having been said, whether the assets are cost effective
21 relative to the market can be truly determined only with hindsight 30 years from
22 now. A forecast of whether they are likely to be cost effective depends entirely on
23 the market price forecast used. Near-term prices are forecast to be relatively low,

1 reflecting the glut of capacity coming on line in the western U.S. in 2002-3 and the
2 recessionary economy. Of course, these near-term forecasts are not relevant, since
3 the rate freeze remains in effect through most or all of 2004. The only prices that
4 matter are post-freeze prices. Market data on forward prices for the relevant period
5 beginning in late 2004 or 2005 and extending for the life of the assets are not
6 available or are of dubious quality. Forward markets beyond the next few quarters
7 are illiquid and reflect small trading volumes. It simply is not possible to determine
8 from forward market data what price the competitive market would pay for 1,700
9 MW of capacity in Arizona for the next 30 years or so. Even if forward markets
10 were more liquid and robust, there is no assurance that current forecasts of market
11 prices will prove more accurate than the sometimes wildly inaccurate forecasts of
12 the past.¹⁴

13 **Q. Do long-term contract prices provide any guidance on the competitive value of**
14 **the output of the PWECC assets?**

15 **A.** No. Long-term contract prices generally are unobservable. The last group of long
16 term contracts for which price terms were disclosed publicly was the CDWR
17 contracts signed between February and August of 2001.

18 **Q. Do you have an opinion, qualitatively, of how long-term prices could be**
19 **estimated?**

¹⁴ As traders always point out, a forward price curve is not the same thing as a price forecast. Forward bid-offer prices are the prices at which forward products will transact today. Any market participant may have a quite different price forecast. For example, in 2001, Pinnacle West's price forecasts were below the market curves of the time, although they still showed that a cost-based PPA brought considerable value to APS's customers.

1 A. Yes. In the short run, prices need to be high enough to do two things: first to pay
2 the variable cost of the marginal producer – the highest cost unit needed to meet
3 load at particular points in time (e.g. hourly). Second, prices need to yield enough
4 margin to keep sufficient plant available to meet load reliably. In general, this is an
5 additional amount that must cover, at a minimum, the “going forward” cost of
6 plant. This includes (in addition to fuel) operation and maintenance expense
7 (including capitalized future expenditures) associated general and administrative
8 expense and property taxes. It needn’t cover the entire sunk cost of capital
9 investment. The shorthand for this is “short run marginal cost”. The explanation I
10 have given varies slightly from the economist’s standard definition of the short run
11 marginal cost of energy in order to reflect the need for system operating reserves, a
12 factor that is unique to electricity.

13 In the long run, the expected (approximately, the average) level of prices
14 needs to be high enough that needed new entry will be attracted. Historically, this
15 was achieved in a different manner, by rolling new plant into ratebase. This might
16 lower, but more typically raised, the average prices seen by ratepayers in the first
17 years of plant operation. In a competitive wholesale market (i.e. absent cost-based
18 regulation), the constraint that prices must be high enough to attract needed entry
19 determines a market price that is earned by all competitive market participants. The
20 short hand term for such prices is “long run marginal cost” or LRMC.

21 Q. If you know, does your description match how Pinnacle West forecasts prices?

22 A. Yes. I have worked with APS’s planners for a number of years and can confirm
23 that this is how they typically have forecasted prices. That is, they use short run

1 marginal cost in the near term and LRMC for years past when markets come into
2 balance. I note that I am talking about the planners who do long term analyses, not
3 about traders whose focus is short term and whose methodology is different.

4 **Q. Do you agree that this is an appropriate way to forecast prices?**

5 A. Generally yes, particularly for studies of generation options that will have long
6 lives. However, this type of "fundamental" price forecasting is not very good at
7 forecasting price volatility or even the year-to-year trajectory of prices. It used to
8 be a common practice to use short run marginal cost to forecast prices in the near
9 term, then to trend prices up to long run marginal cost gradually as the need for new
10 capacity approached. However, this ignores the "boom-bust nature of commodity
11 markets, including electricity. In reality, new capacity will not generally be built on
12 a "just in time" basis, thus capping prices at long run marginal costs, then holding
13 steady at long run marginal cost for the remainder of time. Rather, it reasonably
14 can be anticipated that the elimination of surpluses will result in quite high shortage
15 prices until supply fully responds. This is a major lesson learned from the Western
16 power crisis of 2000-1 as well as from other commodity markets.

17 Forecasts made today that ignore the "boom" portion of the cycle generally
18 will have a downward bias, taken as a whole; that is, they will unsystematically
19 under-forecast future prices. Since they typically will have a near term "bust"
20 component with no off-setting "boom", they would also, on average, forecast
21 revenues to new entrants that are below full costs. If potential entrants acted on
22 such forecasts, entry would not occur. If the prices were to occur in fact, such entry
23 as occurred would not be profitable

1 This systematic bias is relevant to any evaluation of the proposed ratebasing
2 of the PWEC Arizona units. This bias is compounded by, and indeed arises
3 principally from, the sensitivity of such an analysis to the timing of future price
4 changes.

5 **Q. Why does the timing of price changes matter to the cost-effectiveness of**
6 **ratebasing the PWEC Arizona assets?**

7 A. As was demonstrated by the non-PWEC bids in Track B, as well as by Pinnacle
8 West's traders forward price curves used in evaluating the bids, the near-term
9 market is in a "bust" cycle. That is, these prices are below the level needed to
10 support new entry.

11 However, we can know with reasonable certainty that ratebasing the PWEC
12 assets will be a good deal for ratepayers, relative to buying from a market that is in
13 "long run equilibrium," that is, with prices equal to long run marginal costs. This is
14 because the PWEC assets came on line in 2001-3 and were built with less inflated
15 dollars that will be the case for the future new plants, the cost of which will
16 determine long run marginal cost and thus set long run marginal cost-based prices.
17 Moreover, the PWEC assets are partly depreciated. These two factors will create a
18 continuous wedge of benefits from ratebasing these assets relative to buying at long
19 run marginal costs.

20 This can be shown with a simple numerical example. Suppose that APS's
21 best alternative to ratebasing these assets is to sign a new long-term contract with
22 new generation to begin when the PWEC contract expires in 2006. The PWEC
23 assets will be roughly four years old. If inflation over the 2002-6 period averages,

1 say 2.5 percent, and depreciation is 3 percent per year, the capital cost of the new
2 facility will be around 22 percent higher. It will remain that much higher for the
3 life of the PWECC assets.¹⁵

4 **Q. Does this discussion mean that you could derive a forward price curve to**
5 **compare against the PWECC assets by using short run marginal cost or**
6 **forward price curves in the near term and long run marginal cost once the**
7 **current supply glut is exhausted?**

8 **A.** No. This misses the factor that makes such forecasts biased downward. Electricity
9 has been shown to be like other commodities in that it is subject to "boom-bust"
10 cycles. The current over-supply is the "bust" from a generator's perspective. To
11 simply move smoothly from the "bust" to long run equilibrium misses the "boom"
12 part of the equation and would systematically undervalue the PWECC assets

13 **Q. Can you give a quantitative example of what the "boom" prices look like?**

14 **A.** Yes. In concept, the "boom" prices have to be enough higher than long run
15 marginal cost to offset the extent to which "bust" prices are below it. It is the
16 nature of commodity cycles involving capital intensive facilities that "booms" are
17 shorter than "busts". That is, when prices are high, so much new capacity is built
18 that the over-supply can last several years.

19 What has happened in Western power markets over the past five years
20 provides a very telling example. Beginning with the establishment of the California
21 PX and ISO in April 1998¹⁶, prices were very low for two years. This was followed

¹⁵ This example calculation ignores tax-timing effects and will somewhat overstate the difference.

¹⁶ Prices were low before April of 1998, but the market data that I am addressing date only from the beginning of the PX and ISO markets.

1 by the very high prices during the 13-month crisis period and prices tailing off for
2 another couple of months. Thereafter, prices returned to the low levels of 1998-9.¹⁷

3 As part of my testimony in the California refund litigation, I examined the
4 contribution margin¹⁸ for a hypothetical new combined cycle unit and a
5 hypothetical new combustion turbine unit coming on line in April 1998. In that
6 analysis, I assumed that the plants' output was sold in the PX day-ahead market
7 until the PX ceased to function, and then in the ISO balancing market. Both types
8 of units were deeply loss making, earning less than half of what was needed to
9 cover fixed costs in the pre- and post-crisis periods. It turned out that the full
10 amount of the very high margins earned during the crisis period was necessary to
11 get the units back to income levels sufficient to support entry.

12 Specifically, I testified that in the first year, the contribution margin for a
13 new combined cycle unit would have been \$55/kW and in the second year would
14 have been \$65/kW. In the year beginning April 2000, the margin would have been
15 \$377/kW and in the year beginning April 2001 (catching the last part of the crisis
16 period) would have been \$83/kW. In the year beginning April 2002, the
17 contribution margin would have been \$42/kW. This averages \$125/kW-year,
18 approximately the long run marginal cost of such a unit. The peaking unit fared
19 even worse.

¹⁷ While I have couched this in terms of prices, this is not strictly accurate. What matters is not prices as such but the margins over fuel costs that pay for fixed cost and a return on investment. Over this period, there was a great deal of variability in gas prices, which also affected prices. The pattern that I described is the pattern of margins, though the pattern of prices is similar.

¹⁸ The contribution margin is the "profit" earned in excess of out-of-pocket variable costs that can be used to offset semi-fixed costs (e.g. operations and maintenance) and to provide a return on and of investment.

1 While this was an eye-opening result, on reflection, it was not surprising. If
2 a unit is earning less than half of the required margin during a four-year "bust"
3 period, it must earn more than three times long run marginal cost margin during the
4 "boom" year. Stated slightly differently, the "boom" period margin needs to be at
5 least 6 times the margin during the "bust" period if the unit is to cover long run
6 marginal cost over the whole cycle.¹⁹

7 **Q. Does the California experience teach any other lessons about "boom-bust"**
8 **cycles?**

9 A. Yes. There was general unanimity among all of the witnesses that the root cause of
10 the high prices was a shortage of generation. There was less unanimity about the
11 role of other factors (e.g. market design, market manipulation); however, even those
12 experts who laid much of the blame on the exercise of market power testified that
13 the ability to exercise market power and substantially affect prices was a result of
14 the underlying shortage of power. Published analysis entered into the record in that
15 case²⁰ showed a systematic relationship between tight reserve margins and the
16 ability of generators to raise prices substantially above the short-term marginal cost
17 of energy. Hence, the next substantial price spike (setting aside the effects of gas
18 prices) should coincide with the working off of the current capacity surplus.

¹⁹ This assumes that it earns half of the required contribution margin in glut years, a better performance than seen in the western power markets over the past five years. Under this assumption, it must cover its full cost in the boom year, plus make up the half that was not covered during the other four years. Six halves is six times the glut margin.

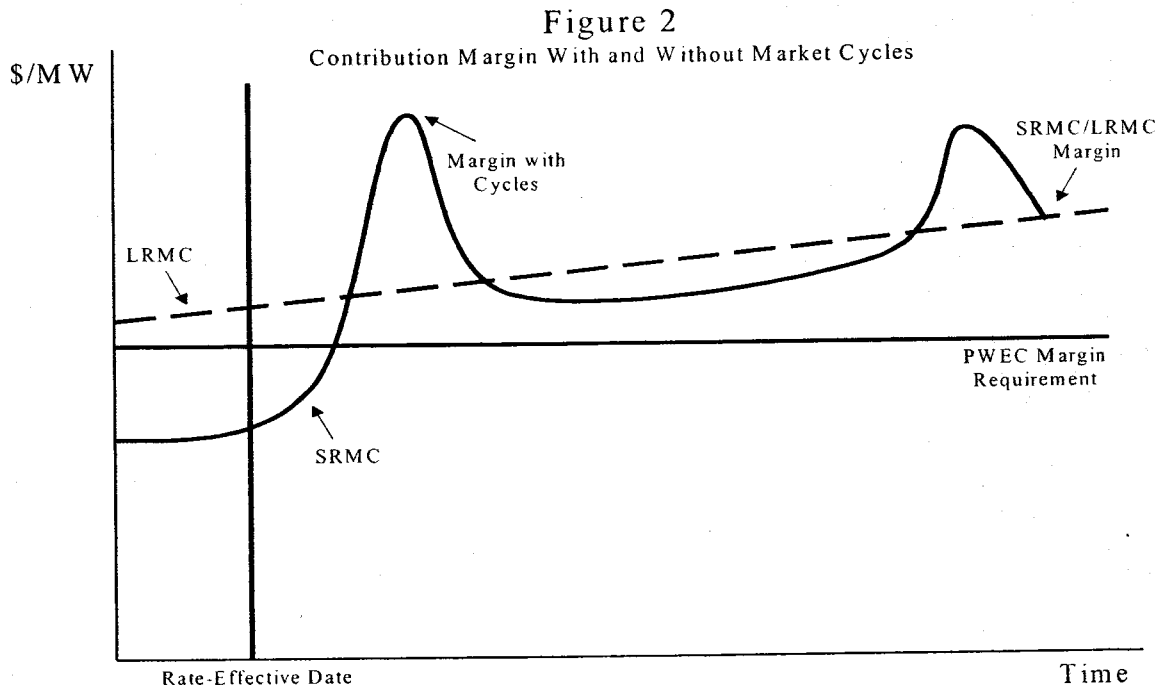
²⁰ Borenstein *et al.*, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," 92 *American Economic Review* (Dec, 2002). Cited in Exhibit No. CSA-2, Prepared Testimony of Steven E Stoft, Ph.D on Behalf of the California Electricity Oversight Board and the California Public Utilities Commission, Exhibit No. CSA-2 in FERC Docket No. EL00-95-075 *et al.*

1 Q. Can you provide a numeric example of why it is important to take into account
2 the timing of the next "boom" period in any going-forward evaluation of rate
3 basing the PWECC assets?

4 A. Yes. Figure WHH-2 contrasts between the two methods of forecasting that I have
5 just described. Common to both examples are four assumptions. First, new
6 capacity is needed in 2007, an assumption that I believe to be valid for reasons I
7 will discuss later. Second, the cycle is eight years long. I believe that this
8 assumption is ballpark correct, but it is of no significance to the analysis; any
9 reasonable assumption would yield similar results. Third, I assume that over the
10 course of each such cycle, the net present value of prices is equal to long run
11 marginal costs. Fourth, I reflect the fact that the book cost of the PWECC assets is
12 below the cost of an otherwise identical unit (the marginal cost-determining unit)
13 coming on line in 2007.

14 "Prices" used are annual per-kW contributions to fixed cost and financing
15 costs, not KWh prices. That is, the time weighted average price over a cycle is
16 sufficient to cover the annualized cost (return on and of, plus fixed O&M) of a new
17 combined cycle unit. The contribution margin permits the analysis to abstract from
18 variable costs, principally fuel. Near-term prices in the buy-from-market case are
19 assumed to be below LRMC through 2006. In the purchase case, they are set by the
20 ratebase cost of the units.

21 In both cases, long run marginal cost is the same. The sole difference
22 between the cases is whether the "boom-bust" nature of the market is taken into
23 account or not.



1
2
3
4 Because the PWEC Arizona assets enter into ratebase relatively near to the
5 beginning of a boom, the value of the assets is greater in the boom-bust model.
6 The fact that it is much more cost-effective for ratepayers if APS acquires the assets
7 at book value near the beginning of a "boom" hardly is surprising. The acquirer
8 avoids the cost of ownership for much of the "bust" period and attendant low prices
9 for off-system sales, and is primed and ready to avoid high market prices during the
10 "boom" period. Of course, this result arises solely from the fact that the assets are
11 acquired at book value. The market value of assets will rise as the anticipated
12 boom period gets closer. Thus, for example, assets purchased in California that

1 provided energy during the "boom" actually were worth substantially more than
2 their value under long run marginal cost conditions.

3 **Q. Does your example include the value of the asset purchase in terms of**
4 **enhanced reliability during periods when the market is tight?**

5 A. No. The example assumes that APS will be able to buy all of the power that it
6 needs from the market. In reality, we know from the Western power markets crisis
7 of 2000-2001 that while utilities such as the Arizona utilities and LADWP that
8 controlled the resources that they needed avoided rolling blackouts and power
9 emergencies, the power-short IOUs in California did not.

10 **Q. You have emphasized the importance of acquiring capacity close to a boom**
11 **period. Have there been studies that suggest how long it will take before a**
12 **shortage of capacity reemerges in the western U. S., setting off another round**
13 **of scarcity prices?**

14 A. Yes. A recent California Energy Commission study²¹ concluded that reserves
15 available to California should be adequate for the next two years, but that continued
16 adequacy required additional conservation measures and/or new capacity. A
17 review of the CEC's calculations actually is a bit more alarming. First of all, it
18 assumes merely average temperature conditions. One-year-in-ten temperatures
19 increase requirements by between 6.5 and 7 percentage points. Second, while only
20 plant scheduled to be completed in 2003 or at the latest early 2004 can be regarded
21 as committed to be built, the CEC assumes an additional nearly 4,000 MW of

²¹ "California 2003 Electricity Supply and Demand Balance and Five-Year Outlook", available at
http://www.energy.ca.gov/electricity/2003_SUPPLY_DEMAND_PEAK.pdf

1 capacity is built in California in the few years after that period, primarily to come
2 on line by the summer of 2005. Without that capacity, California has inadequate
3 operating reserves by 2006-7 under normal weather conditions and by 2005 in one-
4 year-in-ten temperature conditions. Third, the study assumes that California can
5 count on nearly 8,500 MW of on-peak imports in each year. The bulk of these are
6 stated to be under contract. However, the study assumes that 2,700 MW of imports
7 are available in each year beyond the amounts contracted.

8 Building 4,000 MW of new capacity in California, primarily in 2005, is not
9 consistent with prices that remain below long run marginal costs. The assumed
10 level of availability of imports also is highly questionable. Contracted imports
11 already include a substantial (albeit unknown) amount of Desert Southwest
12 merchant capacity.²² As Mr. Bhatti testifies, Arizona load growth likely will
13 absorb all of the available surplus of merchant capacity in Arizona within two to
14 three years. APS, in particular, is forecast to be 1,100 MW short, even taking into
15 account all of the PWEC Arizona capacity. From where, then, will California get
16 the additional 2,700 MW of imports? It is precisely this kind of blind faith reliance
17 on non-California generation that was the root cause of the power crisis of 2000-1
18 that dragged down the entire West.

19 While load forecasting is highly uncertain, and forecasting reserve levels
20 still more so, the foregoing suggests that (unless actions not currently apparent are

²² Nearly all of the imports (other than capacity owned by LADWP and SCE) likely relates to the contracts signed with CDWR. One of those contracts is with Sempra. In view of the fact that it did not bid into the Track B auction, it is likely that Sempra is using Mesquite to fulfill part of its contract. Other contracts are with power merchants who are relying on contracts with unknown generators. At least some of these

1 taken) the Western U.S. will again be in a reserve deficit situation by around 2006
2 or 2007. Indeed, under one-in-10 weather, unless the phantom new capacity is built
3 and the rest of the WECC remains in substantial surplus, California will be deficit
4 in operating reserves to about the same degree as in 2000-1 by the 2006-2007
5 timeframe. Even this grim result assumes low-normal hydro, not the highly adverse
6 conditions experienced in 2000-1 and assumes no "gaming" of the market that
7 involves the withholding of capacity.

8 As happened in 2000-1, when California catches cold, the rest of the West
9 catches pneumonia. As California bids away the remaining uncommitted capacity
10 from the Desert Southwest, price arbitrage between the markets will cause prices to
11 rise to more-or-less equivalent amounts. Of course, to the extent that APS's
12 ratepayers are protected by owning assets or by long term purchased power
13 agreements, such a crisis will not affect them adversely and may even benefit them
14 to the extent that APS has excess energy to sell into the market.

15 **Q. Is this view of the market consistent with the actions of non-PWEC bidders in**
16 **the Track B auction?**

17 **A.** Yes. As discussed earlier, with minor exceptions, bidders did not offer to sell into
18 the auction beyond 2005.

19 **Q. If sellers anticipate a "boom" spike in prices in the middle of the decade, how**
20 **would this affect their offers for contracts to replace or supplement the**
21 **contracts that are due to expire at the end of 2006?**

contracts are with Desert Southwest generators. As Mr. Bhatti testifies, Pinnacle West believes that approximately 3,000 MW of Arizona merchant capacity has been sold out of state.

1 A. They would price this into their contract offers. Contract offer prices are the risk-
2 adjusted equivalent of expected future short-term prices. This is both common
3 sense and demonstrated by the long term contracts signed during the last power
4 crisis.

5 Q. Would this calculus apply to PWEC as well as to other bidders?

6 A. Yes. PWEC would face the same opportunities in export markets as would other
7 generators and power marketers. A profit maximizing PWEC would not sell to
8 APS for less than it could receive elsewhere, particularly having twice offered its
9 capacity to APS's customers at cost-of-service prices and been turned down.
10 Further, unless someone else builds new capacity within the Valley load pocket,
11 PWEC would face no effective competition to meet the reliability must run
12 requirement. Doubtless, FERC market power mitigation would place some limits
13 on what it could charge. However, under current policies, the permitted price
14 would certainly be no less than the cost of ratebasing the West Phoenix plant.

15 **X. CONCLUSIONS**

16 Q. Please summarize your conclusions.

17 A. My conclusions can be summarized briefly as follows. First, the PWEC Arizona
18 units were prudently planned to meet APS's load. Second, they are used and useful
19 in meeting that load. Third, they were constructed at reasonable costs, consistent
20 with the cost of similar units built by other companies. Fourth, the Track B
21 responses signal that the market is likely to tighten at about the time that existing
22 contracts end. Fifth, this likely tightening makes it quite risky in terms of
23 reliability, prices and price volatility, to rely on the market for the capacity that

1 ratebasing these assets would cover. Sixth, ratebasing the PWEC assets likely will
2 be economic relative to the market for the capacity and energy that they provide.

3 **Q. Does this complete your prefiled direct testimony in this proceeding?**

4 **A. Yes, it does.**

5

Appendix A

WILLIAM H. HIERONYMUS — Vice President

Ph.D. Economics, University of Michigan
M.A. Economics, University of Michigan
B.A. Social Science, University of Iowa

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators, and policymakers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy, and regulatory issues. Dr. Hieronymus has spent the last fourteen years working on the restructuring and privatization of utility systems in the U.S. and internationally. In this context he has assisted the managements of energy companies on corporate and regulatory strategy, particularly relating to asset acquisition and divestiture. He has testified extensively on regulatory policy issues and on market power issues related to mergers and acquisitions. In his twenty-five years of consulting to this sector, he also has performed a number of more specific functional tasks, including analyzing potential investments; assisting in negotiation of power contracts, tariff formation, demand forecasting, and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of energy sector clients before regulatory bodies, federal courts, and legislative bodies in the United States and United Kingdom. He has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

- Dr. Hieronymus serves as an advisor to the senior executives of electric utilities on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. Related to some of these assignments, he has testified before state agencies on regulatory policies and on contract and asset valuation.
- For utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers on which he has testified are Sempra (Enova

and Pacific Enterprises), Xcel (New Century Energy and Northern States Power), Exelon (Commonwealth Edison and Philadelphia Electric), AEP (American Electric Power and Central and Southwest), Dynegy-Illinois Power, Con Edison-Orange and Rockland, Dominion-Consolidated Natural Gas, NiSource-Columbia Energy, E-on-PowerGen/LG&E and NYSEG-RG&E. He also submitted testimony in mergers that were terminated for unrelated reasons, including Entergy-Florida Power and Light, Northern States Power and Wisconsin Energy, KCP&L and Utilicorp and Consolidated Edison-Northeast Utilities. Testimony on similar topics has been filed for a number of smaller utility mergers and for asset acquisitions. Dr Hieronymus has also assisted numerous clients in the pre-merger screening of potential acquisitions and merger partners.

- For utilities seeking to establish or extend market rate authority, Dr. Hieronymus has provided numerous analyses concerning market power in support of submissions under Sections 205 of the Federal Power Act.
- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.
- For generators and marketers, Dr. Hieronymus has testified extensively in the regulatory proceedings concerning the electricity crisis in the WECC that occurred during May 2000 and May 2001. His testimony concerned, *inter alia*, the economics of long term contracts entered into during that period the behavior of market participants during the crisis period and the nexus between purportedly dysfunctional spot markets and forward contracts.
- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC and in ISO-New England's market power mitigation rules.
- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.
- As part of a large planning and analysis team, Dr. Hieronymus assisted a Midwest utility in developing an innovative proposal for electricity industry restructuring.
- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation and more recently before FERC in connection with transactions related to PG&E's bankruptcy and on the contracts signed between merchant generators and various buyers.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.
- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.
- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.
- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.
- He has made numerous presentations to U.S. utility managements regarding overseas electricity systems.
- For an East Coast electricity holding company, Dr. Hieronymus prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand-management programs as alternatives to new plant construction.
- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico, and before the Federal Energy Regulatory Commission regarding plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant costs for tariff-setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives, and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided

extensive support to counsel, including preparation of interrogatories, cross-examination support, and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire, and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that were then under construction. His testimony has covered the likely cost of plant completion; forecasts of operating performance; and extensive analyses of the impacts of completion, deferral, and cancellation upon ratepayers and shareholders. For the senior managements and boards of utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning the continuance of construction.
- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.
- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.
- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.
- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system.
- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.

U.K. Assignments

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional distribution and retail supply companies focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the

regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing commercial capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.
- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.
- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.
- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.
- He assisted one of the Regional Electricity Companies in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.
- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this

WILLIAM H. HIERONYMUS — Page 6

assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.
- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command-and-control system to a decentralized, corporatized system.
- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.
- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.
- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.
- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.
- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.
- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate

under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.
- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.
- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.
- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section 133.
- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.
- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.
- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force, and it formed a basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.
- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.
- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.
- For state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.
- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.
- For a Midwestern electric utility, he provided consulting assistance in improving the client's load forecast, and testified in defense of the revised forecasting models.
- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus assists clients in Hart-Scott-Rodino investigations by the Antitrust Division of the U.S. Department of Justice and the

Federal Trade Commission. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality. In two Surface Transportation Board proceedings, he testified on the sufficiency of product market competition to inhibit the exercise of market power by railroads transporting coal to power plants.

- For a landholder, Dr. Hieronymus examined the feasibility and value of an energy conversion project that sought a long-term lease. The analysis was used in preparing contract negotiation strategies.
- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has been an invited speaker at numerous conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervener strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers.

Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army

Testimony
of
John H. Landon,
Ph.D.

TESTIMONY OF JOHN H. LONDON
ON BEHALF OF
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-03-_____

MANAGING PRINCIPAL AND DIRECTOR,
ENERGY AND TELECOMMUNICATIONS PRACTICE,
ANALYSIS GROUP, INC.

June 27, 2003

TABLE OF CONTENTS

<u>DIRECT TESTIMONY OF JOHN H. LANDON</u>	1
<u>I. QUALIFICATIONS AND PURPOSE OF TESTIMONY</u>	1
A. <u>BACKGROUND</u>	1
B. <u>PRIOR EXPERIENCE</u>	3
C. <u>PURPOSE OF TESTIMONY</u>	3
D. <u>SUMMARY AND CONCLUSIONS</u>	4
<u>II. THE VERTICALLY-INTEGRATED UTILITY</u>	6
A. <u>HISTORICAL PERSPECTIVE</u>	6
B. <u>TRADING OFF EFFICIENCIES FROM VERTICAL INTEGRATION AND COMPETITION</u>	10
C. <u>RECENT DEVELOPMENTS</u>	11
<u>III. DISCUSSION OF POLICY CHOICES AND CONCLUSIONS</u>	14
A. <u>TRADE-OFFS BETWEEN VERTICAL INTEGRATION AND CONTRACTING FOR GENERATION</u>	14
B. <u>BENEFITS FROM VERTICAL INTEGRATION</u>	16
C. <u>DISTRESSED STATE OF MERCHANT GENERATION INDUSTRY</u>	21
D. <u>ADDITIONAL RISKS OF RELIANCE ON LONG-TERM CONTRACTS FOR GENERATION</u>	25

APPENDIX A

ATTACHMENT ____ JHL-1

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1 **Q. What subjects did you teach during this period?**

2 A. I taught regulatory economics, microeconomics, industrial organization, antitrust
3 economics, and economic forecasting.

4 **Q. Where were you employed after leaving the University of Delaware?**

5 A. I was employed by National Economic Research Associates (NERA) from 1977 to
6 1997 first as a Senior Consultant, and, eventually, as a Vice President, a Senior
7 Vice President, and finally as a member of the Board of Directors.

8 **Q. When did you join Analysis Group?**

9 A. I joined Analysis Group in March of 1997.

10 **Q. What has been the nature of your assignments at NERA and Analysis**
11 **Group?**

12 A. Much of my work over the last twenty-five years has been on issues relating to the
13 application of economic principles to the electric utility industry. I have
14 participated in numerous projects addressing economic and related antitrust issues
15 before the Federal Energy Regulatory Commission (FERC), the Nuclear
16 Regulatory Commission (NRC), the Securities and Exchange Commission (SEC),
17 state regulatory commissions, and federal and state courts.

18 **Q. Please briefly outline your electric utility-related background.**

19 A. I studied regulatory economics both as an undergraduate (Michigan State with Dr.
20 Joel Dirlam) and as a graduate student (Cornell University with Dr. Alfred Kahn).
21 I was one of the graduate assistants who provided research assistance for Dr. Kahn
22 as he wrote his seminal work, *Economics of Regulation*. As a faculty member at



1 Case Western Reserve University and the University of Delaware, I taught
2 regulatory economics and authored or co-authored several articles and book
3 chapters focused on economic aspects of the electric utility industry. In my more
4 than 25 years of practice as an economic consultant, I have spent the majority of
5 my time on issues involving electric utilities.

6 ***B. Prior Experience***

7 **Q. Have you previously testified as an expert on the electric utility industry?**

8 A. Yes. I have testified on many occasions before state and federal courts and
9 regulatory agencies on a variety of matters. These matters include: deregulation,
10 affiliate relations, competition and market power, rate making, performance-based
11 regulation, transmission governance, demand-side management, cost allocation
12 and pricing.

13 **Q. Before which state regulatory commissions have you testified?**

14 A. I have provided testimony before the state regulatory commissions of Arkansas,
15 Arizona, California, Delaware, Florida, Illinois, Iowa, Louisiana, Maryland,
16 Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Jersey,
17 New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Texas, Vermont and
18 West Virginia.

19 ***C. Purpose of Testimony***

20 **Q. What is the purpose of your testimony in this proceeding?**

21 A. I have been asked by Arizona Public Service Company (APS) to provide the
22 Arizona Corporation Commission (ACC) an overview of recent events in the on-

1 going evolution of the electricity industry that bear on the evaluation of long-term
2 energy supply alternatives. My testimony focuses on evaluating the necessary, but
3 sometimes overlooked, trade-offs in economic efficiencies between two
4 alternative models of long-term electricity supply: 1) vertical integration of
5 generation within the traditional electric utility and 2) contracting for generation
6 supplies with unrelated, and, for the most part, unregulated third parties. I have
7 also been asked to discuss specifically how the current financial condition of some
8 merchant generators and enforcement problems associated with long-term power
9 supply contracts affect the evaluation of efficiency trade-offs.

10 ***D. Summary and Conclusions***

11 **Q. Please summarize your testimony and conclusions.**

12 A. 1. Cost-of-service regulation in Arizona generally has provided reliable
13 service at relatively low prices. However, regulators and others have sought
14 partial restructuring of traditional regulation in the state in order to capture
15 competitive market efficiencies. These proposals originally included the
16 introduction of a new system of generation supply based on unregulated electricity
17 providers.

18 2. There are recognized and substantial economic efficiencies from vertical
19 integration, including:

- 20 • Coordinating technological and planning interdependencies;
- 21 • Conveying efficient prices and cost signals throughout the production
- 22 process;



- Improving non-price information flow, for example, regarding operating constraints;
- Reducing uncertainty by relying on internally supplied resources;
- Reducing transaction costs; and
- Providing a self supply alternative to supplement, discipline, and hedge the market.

There is also the potential for efficiencies from relying on competition among merchant generators to supply certain long-term resource needs. Regulators need to weigh the trade-offs between these known and potential efficiencies in deciding the appropriate roles of each in meeting utilities' long-term resource needs.

3. Vertically-integrated utilities can benefit from the efficiencies of both vertical integration and the competitive wholesale market by using the latter to supplement the former, and using the former to hedge the latter.

4. The suitability of relying on merchant generation for a utility's long-term resources is a function of four criteria: functioning competitive markets, financially sound counterparties, adequate means of hedging contractual risks, and enforceable contracts. In today's environment, shortcomings in each of these areas increase contractual and operational risks and their associated costs.

5. Regulators should support their jurisdictional utilities acquiring ownership and control of capacity resources if, after appropriately reflecting all economically relevant risks, it represents a cost-effective and reliable way to meet customer requirements.



II. THE VERTICALLY-INTEGRATED UTILITY

A. Historical Perspective

Q. Please discuss the provision of electricity supply prior to the late-1970s.

A. Commencing in the mid-1930s, with passage of the Public Utility Holding Companies Act of 1935, electricity was supplied primarily by vertically-integrated utilities. This structure reflected the widely-held view that, due to economies of scale and scope, the economic efficiencies from vertical integration overwhelmed any competitive efficiencies in electricity supply. Economies of scale occur when there are decreasing average costs with increasing size; i.e., production from larger plants costs less per unit of output. Economies of scope occur when interrelated activities are performed in coordination; i.e., the costs of joint production of a good or service are less than the sum of the individual costs of production.

By the late 1970s, privately-owned utilities accounted for around 75 percent of generating capacity and were regulated by state public utility commissions on a "prudent cost-of-service" basis.¹ That is, for the most part, these firms had the opportunity to earn a regulated rate-of-return from their customers on the depreciated prudent original cost of plant in service, plus recovery of other reasonable expenses. Integrated electric utility operations were generally concentrated in geographically defined service territories, with limited



1 transmission interconnections between them. Transactions between integrated
2 utilities were small relative to self-supply; in short, most utilities were largely self-
3 sufficient.

4 During much of this period, regulation of prices was based on *ex post*
5 allocations of already incurred costs and expectations of their trends. As a
6 consequence of regulation, incentives to achieve maximum operational efficiency
7 were dulled. When inflation outpaced efficiency improvements, rates tended to
8 rise. Some regulators used ratemaking to implement social goals such as
9 subsidizing designated producers or classes of consumers; this led to further cost
10 increases and introduced additional inefficiencies. Commencing with the effects
11 of the Arab Oil Embargo of 1973-74, deteriorating economic conditions,
12 heightened inflation, and increased interest rates greatly complicated regulated
13 utilities' efforts to build new plants. Problems encountered in constructing
14 nuclear and coal plants during the 1970s and 1980s heightened awareness of the
15 hidden costs of this system of regulation to customers, regulators and utilities—
16 costs that at least partially offset its benefits.

17 **Q. Did these concerns result in changes in public policy?**

18 **A.** Yes. These events led regulators to take a more proactive role in utility cost
19 control. For example, cost disallowances and rates rising less rapidly than costs
20 became more common. In addition, passage of the Public Utility Regulatory
21 Policies Act of 1978 (PURPA) signaled the beginning of a trend that was to lead

¹ In 1979, 97 percent of generation was owned by a combination of privately-owned utilities and publicly-owned utilities. Publicly-owned utilities include municipalities, federal market agencies, rural co-ops,

1 to greater emphasis on independent generation supplies. PURPA required
2 jurisdictional utilities to contract with certain generators called qualifying
3 facilities (QFs), at avoided costs, i.e., the cost the utility would otherwise have
4 incurred to supply generation. While PURPA encouraged the use of cogeneration
5 and renewable energy, it had the effect of demonstrating the technical feasibility
6 of using third-party generation to meet a significant portion of vertically-
7 integrated utility load requirements. However, the use of administratively
8 forecasted avoided costs as the basis for QF contracts turned out to be very
9 expensive in several states. Administratively determined utility avoided costs,
10 which formed the basis for long-term QF contracts, reflected a static view of
11 technology, as well as the difficult, and relatively short-lived, economic
12 conditions that utilities faced at the time. As economic conditions improved, and
13 technological advances were achieved, long-term QF contracts were revealed as
14 extraordinarily expensive compared with alternative resources.

15 Later, the Electric Policy Act of 1992 (EPAct), broadened competitive
16 generator eligibility by creating a new class of generators, Exempt Wholesale
17 Generators (EWG), that were exempt from PUHCA requirements. EWGs did not
18 have some of the ownership limitations of QFs, but they also did not enjoy the
19 mandatory utility purchase requirement of PURPA. EPAct also gave FERC the
20 authority to ensure that competitive suppliers had access to markets for their

and so on.

1 products. On the basis of this authority, FERC issued Order 888 in 1996, which
2 called for open access to transmission.

3 **Q. Over this same period, was there a change in the perceived level of economies**
4 **of scale and scope from vertical integration?**

5 A. Yes. The movement away from nuclear power and improvements in the
6 efficiency of small coal plants and combined cycle gas turbines made technical
7 economies of scale less significant in electric generation. Whereas the large
8 nuclear units were around 1,100 megawatts to 1,200 megawatts and required
9 significant upfront investment, today's combined cycle plants are sized as small as
10 100 to 300 megawatts.² In addition, economies of scope from vertical
11 efficiencies, which had been somewhat eroded by the introduction of computer-
12 based information systems, were assumed to be outweighed by the potential
13 benefits of competition.

14 **Q. Were there also changes in the way that vertically-integrated utilities**
15 **evaluated prospective supply options?**

16 A. Yes. Theoretical models were developed that incorporated competitive generation
17 supply as an alternative to projected future plant additions by vertically-integrated
18 utilities. These models also increasingly took into consideration the ability of
19 utility-owned generation to compete effectively for off-system sales. Electric
20 supply models analyzed the construction of facilities on a regional rather than
21 utility-by-utility basis. Wholesale electric markets increasingly provided

² Although individual unit economies-of-scale declined somewhat, there are still significant economies in owning and maintaining multiple units of similar type.

1 competitive options and opportunity for more efficient operations and planning by
2 vertically-integrated utilities.

3 ***B. Trading Off Efficiencies from Vertical Integration and Competition***

4 **Q. Are there tradeoffs between achieving the benefits of vertical integration on**
5 **the one hand and relying solely or primarily on the marketplace on the**
6 **other?**

7 A. Yes, there are.

8 **Q. Please summarize the trade-off in economic efficiency between 1) utility**
9 **vertical integration in the provision of new generating resources and 2)**
10 **relying on the marketplace to provide them.**

11 A. The vertical economies in the generation and delivery of electricity were
12 historically well-known and arose both from economies of scale and scope,
13 including reduced costs of coordination, such as better cost and price signals.
14 Regulation was used to eliminate the market power concerns that otherwise would
15 accompany the single supplier paradigm that resulted.

16 In contrast, economic efficiencies from wholesale or bulk power supply
17 competition were expected to result from market forces applying competitive
18 pressure on providers 1) to achieve lower costs and develop new products, and 2)
19 to pass these lower costs on to their customers in the form of lower prices and also
20 improved product choices. The bases for the benefits of competitive markets, as a
21 general proposition, are also well-known.

1 The movement to restructure the electricity industry away from the
2 vertically-integrated model and to introduce wholesale competition in generation
3 supply has rested heavily on the assumption that any increased efficiency from
4 competition would more than outweigh any loss of the old vertical integration
5 efficiencies.

6 ***C. Recent Developments***

7 **Q. How has the assumption that the efficiency from more competitively-supplied**
8 **generation would outweigh the loss of efficiency from vertical integration**
9 **held up in recent years?**

10 A. Recent developments call the benefits of complete reliance on external market
11 alternatives into serious question.

12 **Q. Why is it that contracting for long-term generation supplies from merchant**
13 **generators may be less economically efficient than self-supply by a vertically-**
14 **integrated entity?**

15 A. First, the two need not be mutually exclusive. Some merchant generation can be
16 used to supplement self-supply. That being said, cost-of-service regulation has
17 evolved new tools. Mechanisms such as periodic rate freezes and performance-
18 based ratemaking, have evolved in many places to supplement traditional cost-of-
19 service regulation. Indeed, Arizona has utilized each of these regulatory tools in
20 the past decade. These developments preserved the economies of vertical
21 integration while supplying increased incentives to utilities to control generation
22 costs. While these mechanisms may not incorporate all of the same incentives to

1 innovation as competitive markets, taken in combination they appear to have
2 allowed rate reductions in many states, including Arizona. In addition, major
3 increases in new plant efficiency have come from improved generation
4 technology. It is notable that much of this recent innovation in generation has
5 come from competing generating equipment manufacturers, not from independent
6 power suppliers.

7 It is also noteworthy that competitive markets are not emerging at a
8 uniform pace or in the manner many expected. In some regions, there is
9 uncertainty in bulk power market design and institutions, transmission governance
10 and retail market development. There are also questions as to whether and when
11 markets for electricity will be sufficiently developed to support many of the
12 theoretical benefits of competition. In addition, recent electricity supply market
13 volatility, along with generation expansion in excess of near term market
14 requirements combined with legislative and regulatory uncertainty, have
15 compounded the financial distress of competitive generators. This distress, in
16 turn, calls into question the financial security of long-term energy contracts,
17 jeopardizing the ability of the utility and its customers to realize their benefits.
18 Long-term security through market arrangements is also reduced by increasing
19 difficulties in the enforcement of long-term generation contracts. Default is
20 largely a concern only when contracts turn out favorable to the buying utility and
21 its customers. To the extent that contracts favor the seller, it is not likely that
22 default will become an issue; and, even if it occurs, the utility should be able to



1 easily obtain equivalent or superior replacement supplies elsewhere. In this
2 testimony, I will concentrate my attention on the financial condition of merchant
3 generators and other factors which increase levels of utility risk exposure under
4 long-term contracts.

5 **Q. Please explain.**

6 A. While there is a surplus of physical generation capacity in some regions that may
7 last for several years, much of it is controlled by entities which have suffered
8 significant impairment of their financial condition. In the Southwest, nearly 6,000
9 MW of new or near-term expected capacity is owned by entities that carry junk
10 bond level credit ratings.³ As I discuss below, there are substantial risks
11 associated with long-term supply contracts with these entities. Regulators should
12 take account of these risks together with the recent volatility of energy markets
13 and a recent history of enforcement issues with long-term contracts. When
14 weighed against the other advantages of vertical integration, they are likely to find
15 that, in Arizona, a substantial continued reliance on the economic efficiencies of
16 vertical integration outweighs the benefits of a substantial shift to outside
17 procurement and disaggregation at the present time. Under these circumstances, it
18 is reasonable for utilities to integrate capacity into their systems through new
19 construction, purchase or transfer of existing generation from an unregulated
20 subsidiary. The balance of this testimony explores these issues.

³ Includes Harquahala plant (1,092 MW) which is under construction. According to PG&E National Energy Group if plant is not transferred to lenders or their designees by June 30, 2003, a default will occur. <http://www.neg.pge.com/refforts.html> (visited June 9, 2003).



1 **Q. How should regulators evaluate the reasonableness of vertically integrating**
2 **capacity into jurisdictional utilities?**

3 **A. Regulators should support their jurisdictional utilities acquiring in ownership and**
4 **control of capacity resources if, after appropriately reflecting all economically**
5 **relevant risks, it represents a cost-effective and reliable way to meet customer**
6 **requirements taking into account all other relevant circumstances.**

7
8 **III. DISCUSSION OF POLICY CHOICES AND CONCLUSIONS**

9 ***A. Trade-offs Between Vertical Integration and Contracting for Generation***

10 **Q. Please discuss the trade-offs between the economic efficiencies from owning**
11 **generation resources versus acquiring varying degrees of output rights via**
12 **contract.**

13 **A. Comparing the two directly requires considerable care, judgment, and experience.**
14 **The nature and source of the efficiencies differ. The efficiencies from vertical**
15 **integration arise primarily from more efficient planning and operational**
16 **coordination between generation and delivery when the investment, maintenance**
17 **and operating decisions are made by a single management. In contrast, economic**
18 **efficiencies from acquiring generation via competitive contracts with unrelated**
19 **entities depend upon market pressure to provide incentives for wholesale suppliers**
20 **to offer alternatives that will be both profitable for themselves and cost-effective**
21 **for the buyer. Vertical integration reduces the reliance on the competitiveness of**
22 **future markets and utility exposure to the risk of market fluctuations, whereas**

1 contracts can only shift some market risks to unregulated market suppliers. The
2 correct balance between the two is a matter for careful judgment—a judgment that
3 may well shift over time.

4 **Q. Please discuss the conditions necessary to realize economic efficiency from**
5 **wholesale electric market competition.**

6 **A.** Maintaining competitive pressure requires well-functioning markets and the
7 means to ensure that contractual arrangements are binding and enforceable on
8 financially viable counterparties.

9 Markets tend to be well-functioning when there are economically sensible
10 and predictable operating and trading arrangements. Today, in the Southwest,
11 these arrangements are not yet fully developed for the supply of electric
12 generation; thus, as in much of the country, the future shape and mechanisms of
13 markets are unknown. As the experience in California has shown, some methods
14 of organizing markets will not lead to economically sound institutions that support
15 competitive and efficient outcomes. At this time, it is unclear whether or when
16 sufficiently well-functioning markets necessary to realize the benefits of
17 competition will be available in Arizona.

18 In addition, the impaired financial condition of merchant generators has
19 greatly undercut the functioning of markets and has led to increased, even
20 unacceptable levels of counterparty risk for long-term contracts. The likely cost
21 of absorbing or mitigating this risk also must be weighed in evaluating the
22 tradeoff between vertical integration and contracting with third parties.

1 ***B. Benefits from Vertical Integration***

2 **Q. Please describe the sources of benefits from vertical integration in supply and**
3 **delivery of electricity.**

4 **A. The benefits from vertical integration arise from:**⁴

- 5 • Technological and planning interdependencies. Where it is most
6 efficient for a good to be passed directly and immediately from one
7 stage to another, the rationale for combining the stages under
8 unitary control is obvious. In electricity, technological and
9 planning interdependencies arise from the need for the system to be
10 continuously in balance between generation, transmission and
11 distribution functions in order to produce and deliver electric
12 service. In competitive markets, the introduction of regionally
13 centralized coordination (such as ISOs or RTOs) is intended to
14 substitute for this source of vertical efficiencies, but gives rise to a
15 new layer of measurement, control and transactions costs. It is
16 necessary, for example, to identify and settle imbalances between
17 participants and to coordinate operation of plants under separate
18 ownership, management and incentives.
- 19 • Conveying efficient price and cost signals throughout the
20 production process is difficult. When marginal input and output
21 costs are not observable in or reflected by the market, they cannot

⁴ John Landon, "Theories of Vertical Integration and Their Application to the Electric Utility Industry," *Antitrust Bulletin* 28 (1983).



1 be used to make decisions to adjust production or change inputs.
2 Vertical integration allows the passing of intermediate goods and
3 services between various production stages at marginal cost, as
4 opposed to regulated prices, or at prices contracted for in advance,
5 neither of which will reflect current marginal costs except in the
6 most fortuitous of circumstances. A long-term contract priced at
7 four cents/kWh, for example, may reflect the supplier's marginal
8 costs of 10 cents at peak periods and of 2.5 cents off-peak.

- 9 • Improved non-price information flow such as that regarding
10 operating constraints, load and capacity projections, and
11 maintenance plans. Vertical integration enables this information to
12 be used within the organization in a more seamless manner to
13 match loads and resources and to supply customer needs. Where
14 utilities acquire capacity from outside parties they must forecast
15 these factors in advance and draft agreements with their
16 counterparties accordingly. As actual circumstances change,
17 utilities relying on outside resources must coordinate or attempt to
18 negotiate any modifications of contractual constraints in real-time
19 with the needs of customers.

- 20 • Reduced uncertainty by relying on internally-supplied resources.
21 Much of this testimony is about the effects of uncertainty regarding
22 the current and future financial well-being of merchant generators



1 and/or on the amount of risk that is inherent in contracts with them.
2 In addition, there are risks associated with evolving markets and
3 the effects of unforeseen developments on contracts and on
4 enforceability of contracts. Relying on internally-supplied
5 resources reduces (although it cannot entirely eliminate) exposure
6 to these risks.

- 7 • Transaction costs in vertically-integrated entities generally are
8 significantly lower than in wholesale competitive markets. For
9 example, for a vertically-integrated electric utility that self-supplies
10 generation, acquiring a block of owned capacity entails upfront
11 costs associated with siting and constructing the plant, and perhaps
12 arranging for sales of any excess capacity. Acquisition of supply
13 from outside parties entails repeatedly incurring transaction costs
14 as contracts expire or require renegotiation. Examples of these
15 costs are costs of soliciting resources, negotiating contracts suitable
16 to the utility's anticipated needs, administering contracts and
17 ironing out any disagreements that may arise during the course of
18 the contract. In addition, any contracted energy or capacity that is
19 excess to the utility's needs must be remarketed with or without the
20 participation and cooperation of the seller.



1 Q. Please describe examples of how these efficiencies are achieved in a
2 vertically-integrated electric utility.

3 A. The following examples demonstrate how efficiencies are achieved in a vertically-
4 integrated electric utility. This list is illustrative, not exhaustive.

5 First, internalizing planning for future resource needs of utility retail
6 customers permits planning and investment decisions to be made in a fully-
7 coordinated manner with respect to existing generation, transmission and
8 distribution investments rather than in a piecemeal fashion. In addition, the
9 standard electricity products that are available do not necessarily match utility
10 load shapes as well as a system designed and operated for that purpose.

11 Second, operating efficiencies are possible when utilities have accurate
12 information on the marginal costs of alternative methods of supplying customer
13 demands and maintaining system regulation and reserves. Accurate marginal cost
14 information enables the utility's resource mix to be dispatched to serve load in the
15 most efficient manner possible given plant operating constraints. When plant
16 operating constraints can be adjusted to improve dispatch and thereby improve
17 overall system efficiency, the vertically-integrated utility has the incentive to do
18 so. A merchant plant owner whose objective is to supply power under already
19 agreed upon terms and conditions may not make similar investments or may make
20 them only if it achieves renegotiation of other aspects of the contract that would
21 be in its favor. In any event, the merchant plant owner would retain the benefit (at



1 least pursuant to the contract terms), in some form, of any investments to improve
2 its plants rather than passing the benefits on to the utility and its customers.

3 Third, generation plant maintenance can achieve economies of scale and
4 scope if the utility's fleet is sufficiently uniform in type and central in location to
5 allow maintenance crews to service efficiently multiple units and eliminate the
6 need to inventory parts for diverse generation plants constructed by multiple
7 manufacturers. For example, the West Phoenix plant was designed to eventually
8 have multiple, similar units at a single site in order to take advantage of economic
9 efficiencies in maintenance. Although merchant generators can sometimes
10 provide a similarly uniform fleet of generating assets, they may be scattered over
11 many states or have obligations to multiple entities who have differing scheduling
12 requirements. In addition, reliability is enhanced when there are robust
13 maintenance crews available to deal with the consequences of any plant failure.

14 Fourth, capital improvements can be undertaken when, if and as they are
15 needed to serve load in the most efficient manner. Decision makers also readily
16 can weigh the relative merits of meeting future needs by expanding, upgrading,
17 replacing, retrofitting and/or adding new plant consistent with their obligations to
18 supply service and existing or planned distribution and transmission investments.
19 Thus, the West Phoenix plant, originally an oil-fired generator, was converted to
20 dual fuel capability in the 1980s. Optimal use of expansion and improvement
21 potentials is complicated when different parties will not profit equally and/or at
22 the same time from changes.



1 Q. Are there other advantages to ownership of generation by vertically-
2 integrated utilities?

3 A. Yes. These include operational efficiencies (i.e., economies of scope) of
4 scheduling multiple units, coordination to maximize the benefits of off-system
5 sales, and system reliability, as well as economic advantages of financing within
6 the regulated entity.

7 ***C. Distressed State of Merchant Generation Industry***

8 Q. Please describe the status of wholesale competitive generation markets today.

9 A. In some regions, wholesale spot markets for generation appear to some observers
10 to be functioning reasonably well. The PJM Interconnection, NEPOOL, and NY
11 ISO are examples. Consistent with concerns over ongoing litigation, longer-term
12 contract markets in these areas are less fully developed.

13 In other areas, including the Southwest region that encompasses Arizona,
14 market development has stalled. In some regions, daily and forward markets for
15 physical generation have withered and are not expected to revive to earlier levels
16 any time soon. Broader financial markets to address the risks inherent in
17 competitively supplying electricity are also not well-developed. Last August,
18 Platts reported that as of July 2002, the volume of daily and forward trading at
19 some key hubs declined by up to 70 percent from year earlier levels.⁵ Trading on
20 publicly regulated exchanges was halted completely for a time; however, on April
21 11, 2003, it resumed on NYMEX on a very small scale.

⁵ "‘Worst is Yet to Come’ for Electric Sector, S&P Says as Financials Slide," *Electric Utility Week*, 18 November 2002, 1.

1 **Q. Please describe the financial health of merchant generators today.**

2 A. In general, the financial health of merchant generators has deteriorated
3 significantly over the past two years. The chart in Attachment____JHL-1
4 provides a graphic illustration of the current credit rating of a number of merchant
5 generators compared with 2001 levels. These generators supplied over 50 percent
6 of all U.S. merchant capacity in 2002. As the attachment illustrates, the credit
7 ratings of every generator have fallen, and more than half have declined from
8 investment grade to junk status. Stock prices also have fallen precipitously. For
9 example, as of the end of May 2003, closing stock prices for Calpine, Reliant and
10 Aquila had fallen from about 80 to more than 90 percent from their highs in mid-
11 2001.

12 **Q. What has led to these declines in merchant generator financial integrity?**

13 A. The primary causes are: 1) a decline in the energy trading business, 2) loss of
14 confidence in the viability of firms in overbuilt and/or immature competitive
15 markets, and 3) the potential future effect of compensation that may be required
16 for past illegal activities.⁶ Generation supply is significantly overbuilt in many
17 regions (and may be expected to remain so for several years), resulting in severely
18 depressed price levels. While these conditions may or may not prevail in the
19 Southwest, they do affect the financial well-being of nationally active merchant
20 generators with operations in the region.

⁶ Peter Rigby, "Merchant Energy Survival Hangs on the FERC's Blueprint for Market Design, Special Report," *Standard & Poor's Utilities and Perspectives*, Vol. 12, No. 10, March 10, 2003, 6.



1 Prices are well below those projected during the planning and financing
2 stages for much of merchant plant. They are so low that merchant generators are
3 having difficulty paying the debt associated with construction. These difficulties
4 are triggering creditors' requirements for increased collateral, performance
5 assurances and more onerous financing terms,⁷ at a time when internally generated
6 cash flow is often at a historic low. While merchant generators are experiencing
7 difficulty meeting their existing obligations, they will need to refinance around
8 \$90 billion in medium-term debt between 2003 and 2006.⁸ This perfect storm of
9 adverse conditions continues to undermine the confidence of the financial
10 community in the ongoing viability of the generators themselves. As a result, it is
11 estimated that \$200 billion in capitalization evaporated in the U.S. energy sector⁹
12 with additional losses outside of the U.S.

13 Creditors' requirements for more and more collateral and other
14 performance assurances reduce companies' ability to conduct business on a going
15 forward basis. As a result of merchant generator financial distress, counterparty
16 risk and market uncertainty is very high, leading to further merchant generator
17 financial distress.

18 **Q. In what way are electricity markets immature?**

19 A. At present, the regulated exchanges such as NYMEX are just beginning to re-list
20 forward electricity contracts for some markets. Instead, electricity forward

⁷ "Morgan Stanley Sees Banks Hiking Reserves for Troubled Energy Firms," *Electric Utility Week*, 31 March 2003, 1.

⁸ "Recalibration of Distressed Assets Begins," *EEnergy Informer*, April 2003, 1.



1 markets are conducted in an *ad hoc* manner on several privately operated
2 exchanges. These exchanges are not regulated¹⁰ and generally lack independent
3 oversight. Forward contract terms and conditions are not standardized; threshold
4 requirements for participation are not high; and trading volumes are light. Thus,
5 forward contracts are insufficient to supply credible hedges against the increased
6 contract risk presented by merchant generators. Long-term forward contracts are
7 substantially less common. This combination of factors combined with the
8 uncertainty as to future market design and rules discussed above demonstrate that
9 electricity markets are immature.

10 **Q. Why does the distressed condition of merchant generators lead to increased**
11 **risk for contracting utilities?**

12 A. Reduced credit ratings and falling stock prices have constrained merchant
13 generators' access to capital, and limited financial resources are absorbed by
14 existing projects and obligations. Distressed merchant generators may not have
15 financial resources for bonding or other acceptable direct performance assurances
16 to contracting utilities. Since, as discussed above, it seems likely that
17 counterparty risks for many merchant generators cannot be adequately hedged at
18 the present time, they must be borne by the contracting utility together with its
19 customers if it signs long-term contracts with merchant generation to supply
20 customer needs.

⁹ Karl Miller and David Haarmeyer, "Powering Up Private Equity," *Wall Street Journal*, 18 March 2003.

¹⁰ "Use of financial derivatives lags in U.S. electricity market," *Electric Light and Power*, February 2003, 19.

1 ***D. Additional Risks of Reliance on Long-Term Contracts for Generation***

2 **Q. Are there other reasons to be concerned about over-reliance on long-term**
3 **contracts with merchant generators at the present time?**

4 **A. Yes. Long-term contracts are complex and are subject to interpretation especially**
5 in the presence of significantly changing market conditions. As I mentioned
6 previously, electricity markets are continuing to develop, and it is not possible to
7 foresee how rapidly or in which directions they will evolve. In addition, there are
8 currently a large number of litigated matters arising from substantial changes in
9 market conditions. These changes, in turn, have led to significant differences of
10 opinion regarding the interpretation of the terms and conditions of pre-existing
11 contracts. In at least some instances, contracts have been renegotiated, or even
12 terminated, in light of changing circumstances. In contrast to the small
13 adjustments that are normal under long-term contracts, many of these disputes are
14 very large in size, running into the millions, and even billions, of dollars. Thus,
15 even if counterparties are financially viable going forward, contractual provisions
16 negotiated in today's environment for hypothetical deliveries several years from
17 now do not necessarily secure future sources of revenue to ensure the financial
18 viability of merchant suppliers in the future.



1 **Q. Are there other sources of supply uncertainty with regard to long-term**
2 **contracts with merchant generators?**

3 A. Yes. In addition to developing markets for electricity, environmental regulations
4 are also evolving and can affect plant owners' willingness and ability to keep their
5 plants in operation. An example of this is Southern California Edison's
6 determination to shut down the Mohave generating station in part due to
7 requirements for increased environmental investments. It is instructive that while
8 Edison's Mohave partners have indicated a desire to make the required
9 investments and continue operating, Edison may be able to shut down the entire
10 plant simply by its unilateral refusal to participate. Were Mohave a merchant
11 plant under long-term contract, these actions by Edison may be excusable as *force*
12 *majeure*. This situation illustrates the vulnerability of even contracts backed by
13 "steel-in-the-ground" to decisions of the counterparty or even its partners over
14 which the purchasing utility may have no control and no effective remedy.

15 **Q. Are you saying that APS should not enter into long-term contracts?**

16 A. No. I am saying that APS and its regulators should weigh all of the risks and
17 benefits of long-term contracting for its generation resource needs against those of
18 plant ownership. APS should seek an appropriate balance of these risks in
19 determining the most advantageous portfolio of resources to serve its customers'
20 needs.

21

1 **Q. What do you conclude about how the ACC should evaluate vertical**
2 **integration versus relying on third-party merchant generation.**

3 A. The Commission needs to weigh security of supply and security of price in its
4 deliberations. Prices are low now; however, the ability to bid at a low price does
5 not guarantee an ability or willingness to deliver at that price under future
6 circumstances, even if suppliers are willing to commit to long-term agreements.
7 There are factors related to the future financial viability of competitive suppliers
8 that are beyond the control of either the ACC or the merchant generators
9 themselves. Furthermore, there are limited means in today's markets to hedge the
10 risks of non-performance by merchant generators.¹¹ Thus, if a buyer of today's
11 long-term contract needs to go back into the market for "cover" in the future, it
12 likely will be at the then current market price, which may very well be above
13 today's contracted price.

14 **Q. Does this conclude your testimony?**

15 A. Yes, it does.

¹¹For example, on June 13, 2003, NRG Energy discontinued deliveries to Connecticut Light and Power pursuant to a ruling by the U.S. Bankruptcy Court for the Southern District of New York. FERC is scheduled to review this matter.



Appendix A

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Dr. Landon has served as an economic consultant to the electric utility, coal, and uranium industries for over 20 years. His consulting experience has been wide-ranging and includes analysis of deregulation, strategic planning, competition, ratemaking, transmission governance, performance-based regulation, statistical benchmarking, demand-side management, cost allocation, and pricing. Dr. Landon has testified more than 100 times before federal district courts, state courts, the Securities and Exchange Commission, the Federal Energy Regulatory Commission, and various state commissions, and has prepared numerous expert reports and affidavits. He has authored or co-authored more than 20 articles published in academic and trade journals, two book chapters, and several monographs.

His litigation work has involved damages assessments, forecasting, merger analysis, market definition and market power, valuation, antitrust liability, cost allocation, and pricing.

Prior to joining Analysis Group, Inc., Dr. Landon was Senior Vice President at NERA, Inc. Previously, he held positions as Associate Professor of Economics at the University of Delaware and Case Western Reserve University. Dr. Landon holds a Ph.D. in Economics from Cornell University.

PROFESSIONAL ACTIVITIES

Member of the Governor of Delaware's Economic Advisory Committee

Director of the Center for Policy Studies at the University of Delaware

A Director of the Delaware Econometric Model Group

Senior Research Associate in the Research Program in Industrial Economics at Case Western Reserve University

Member of the American Economic Association

Associate Member of the American Bar Association

TESTIMONY PROVIDED FOR THE FOLLOWING CLIENTS:

- **Public Service Company of Oklahoma**
On behalf of Public Service Company of Oklahoma, Cause No. PUD 200200038, November 5, 2002, (Direct Testimony), January 14, 2003 (Rebuttal Testimony) and January 23, 2003 (Surrebuttal Testimony).
- **Commonwealth Edison Company**
Before the Illinois Commerce Commission, Docket No. 02-0479, July 2002, (Direct Testimony) and September 6, 2002 (Rebuttal Testimony).
- **Southern California Edison Company**
On behalf of Southern California Edison Company in the matter of arbitration between Southern California Edison Company v. California Department of Water Resources, June 27, 2002. (Direct Testimony)
- **Arizona Public Service Company**
Before the Arizona Corporation Commission, Docket Nos. E-01345A-01-0822, December 12, 2001.
- **Oklahoma Gas and Electric Company**
Before the Arkansas Public Service Commission, Docket No. 00-190-U, September 29, 2000. (Direct Testimony) October 24, 2000 (Rebuttal).
- **Public Service Company of New Mexico**
Before the New Mexico Public Regulation Commission, Case No. 3137, May 31, 2000.
- **Eastern Edison Company**
Before the Superior Court, Commonwealth of Massachusetts, Boston, Massachusetts, on behalf of Eastern Edison Company, March 29, 2000.
- **Florida Power & Light Company**
Before the Florida Public Service Commission, Docket No. 991462-EU, Petition for determination of need for electrical power plant in Okeechobee County by Okeechobee Company, L.L.C., February 18, 2000. (Direct and Supplemental Testimonies)
- **Sierra Pacific Power Company/Nevada Power Company (Nevada Power)**
Comments on proposed Code of Conduct rules filed with the State of Nevada Public Utilities Commission, PUCN Docket No. 97-8001 (Provider of Last Resort), January 26, 2000.
- **Ohio Power Company and Columbus Southern Power Company**
Before the Public Utilities Commission of Ohio, Case Nos. 99-1729-EL-ETP, 99-1730-EL-ETP, December 30, 1999 (Direct Testimony); April 18, 2000 (Supplemental Direct Testimony).
- **Christian Hellwig vs. Autodesk, Inc.**
Before the Superior Court of the State of California for the County of Marin, Case No. 174842, December 14, 1999.

- **Public Service Company of New Mexico**
Comments on proposed Code of Conduct rules filed with the New Mexico Public Regulation Commission, NMPRC Case No. 3106, September 27, 1999.
- **Arizona Public Service Company**
Before the Arizona Corporation Commission, Docket Nos. E-01345A-98-0473, E-01345A-97-0773, and RE-00000C-94-0165, July 21, 1999. (Direct, Rebuttal and Surrebuttal Testimonies)
- **Appalachian Power Company**
Before West Virginia Public Service Commission in West Virginia PSC Case No. 98-0452-E-GI, July 7, 1999. (Direct and Rebuttal Testimonies)
- **Ameren Corporation and Union Electric Company**
Comments on behalf of Ameren Corporation and Union Electric Company filed with the State of Missouri Public Service Commission concerning proposed affiliate transactions rules for electric, gas, and steamheating utilities (Proposed Rule 4 CSR 240-20.015) and marketing affiliate rules for gas utilities (Proposed Rule 4 CSR 240-20.016). (Direct Comments filed June 30, 1999 and Reply Comments filed July 30, 1999)
- **GTE Corporation and Bell Atlantic Corporation Merger**
Before the Public Utilities Commission of the State of California, Application 98-12-005, June 21, 1999. (Report and Rebuttal Testimony)
- **Kathleen Betts v. United Airlines, Inc.**
Before the United States District Court, Northern District of California, Case No. C97-4329 CW, March 25, 1999.
- **Commonwealth Edison Company**
Before the Illinois Commerce Commission, Docket Nos. 98-0147 and 98-0148, October 1998. (Direct and Rebuttal Testimonies)
- **The McGraw-Hill Companies**
Before the United States District Court for the District of Colorado, Civil Action No. 96-Z-1087, October 1998.
- **Nevada Power Company**
Before the Public Utilities Commission of Nevada, Docket No. 97-5034, September 1998.
- **Arizona Public Service Corporation**
Before the Arizona Corporation Commission, Docket No. RE-00000C-94-165, August 1998.
- **Arizona Public Service Corporation**
Before the Arizona Corporation Commission, Docket No. E-01345A-98-0245, July 1998.
- **The Detroit Edison Company**
Before the Michigan Public Service Commission, July 1998.
- **Delmarva Power & Light Company**
Before the Maryland Public Service Commission, Case No. 8738, July 1, 1998.

- **Nevada Power Company**
Before the Public Utilities Commission of Nevada, Docket No. 97-5034, July 1998.
- **Nevada Power Company**
Before the Public Utilities Commission of Nevada, Docket No. 97-8001, June 1998.
- **Delmarva Power & Light Company**
Before the Delaware Public Service Commission, PSC Docket No. 97-394F, May 1998.
- **The McGraw-Hill Companies, Inc.**
Before the District Court, City and County of Denver, State of Colorado, Case No. 96-CV-6977, May 1998.
- **Southern California Edison Company**
Before the Public Utilities Commission of the State of California, Application Nos. 97-11-004, 97-11-011, 97-12-012, May 1998.
- **Commonwealth Edison Company**
Before the Illinois Commerce Commission, Docket No. 98-0013, March, 1998. (Direct, Rebuttal and Surrebuttal Testimonies)
- **Arizona Public Service Corporation**
Before the Arizona Corporation Commission, Docket No. U-0000-94-165, February 4, 1998.
- **Silvaco Data Systems**
Before the Superior Court for the State of California, November 7, 1997.
- **Entergy Gulf States, Inc.**
Public Utility Commission of Texas, April 4, 1997 and October 24, 1997.
- **Delmarva Power & Light Company**
Before the Maryland Public Service Commission, Delaware Docket No. 79-229, August 19, 1997.
- **The McGraw-Hill Companies, Inc.**
Before the United States District Court for the District of Colorado, Civil Action No. 94-WM-1697, July 17, 1997.
- **Donaldson, Lufkin & Jenrette**
In the matter of the arbitration between Donaldson, Lufkin & Jenrette Securities Corporation and Lori Zager, NYSE No. 1996-005868, April 11, 1997.
- **Louisiana Pacific**
Superior Court of the State of California, County of Humboldt, Case No. 94DRO166, February 10, 1997.
- **Hoffmann-La Roche, Inc.**
Superior Court of the State of California, County of Santa Clara, Case No. CV 746366, February 4, 1997.
- **Arizona Public Service Company**
Arizona Corporation Commission, Docket No. R-0000-94-165, November 27, 1996.

- **MidAmerican Energy Company**
Iowa State Utilities Board, Docket No. APP-96-1 and RPU-96-8 (Consolidated), October 30, 1996.
- **California Tennis Club**
Superior Court of the State of California, County of San Francisco, Case No. 972651, September 27, 1996.
- **El Paso Electric Company**
United States District Court, District of New Mexico, Civil Action No. 95-485-LCS, July 2 and 3, 1996.
- **Nevada Power Company**
American Arbitration Association in the matter Saguaro Power Company, Inc. v. Nevada Power Company, AAA Case No. 79 Y 199 0054 95, May 29, 1996.
- **Arizona Public Service Company**
Arizona Corporation Commission, Docket No. U-1345-95-491, March 1 and April 4, 1996.
- **Fireman's Insurance Companies**
Insurance Commissioner of the State of California, Case No. RB-94-002-00, February 9, 1996.
- **Nevada Power Company**
American Arbitration Association in the matter Nevada Cogeneration Associates #1 and Nevada Cogeneration Associates #2 v. Nevada Power Company, AAA Case No. 79 Y 199 0064 95, December 6 and 7, 1995.
- **Beverly Enterprises-California, Inc.**
Superior Court of the State of California, County of San Francisco, Case No. 962589, November 6 and 7, 1995.
- **PECO Energy Company**
Pennsylvania Public Utility Commission, Docket No. I-940032, November 6, 1995.
- **Southern California Gas Company**
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- **Southern Company Services, Inc.**
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- **American Electric Power Service Corporation**
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- **Florida Power & Light Company**
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- **Benziger Family Ranch Associates, dba Glen Ellen Winery, et al.**
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- **The Montana Power Company**
Montana Public Service Commission, Docket No. 93.6.24, June 21, 1993 and October 15, 1993.
- **Consumers Power Company**
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- **Detroit Edison Company**
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- **Florida Power & Light Company**
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- **Intermedics, Inc.**
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- **Eaton Corporation, et al.**
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- **Florida Power & Light Company**
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- **Iowa Public Service Company**
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- **Arizona Public Service Company**
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- **Delmarva Power and Light Company**
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- **Florida Power Corporation**
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- **Cambridge Electric Light Company and Commonwealth Electric Company**
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- **Gulf States Utilities Company**
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- **Utah Power and Light Company, PacifiCorp, PC/UP&L Merging Corporation**
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- **Illinois Power Company**
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July 22, 1988.
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- **Minnesota Power and Light Company**
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- **Gulf States Utilities Company**
Texas Public Utility Commission, Docket Nos. 6755 and 7195, *April 13, 1987*.
- **Gulf States Utilities Company**
Louisiana Public Service Commission, Docket No. U-17282, March 23, 1987 and May 26, 1987.
- **Arizona Public Service Company**
Arizona Corporation Commission, Docket No. U-1345-85-367, February 13, 1987 and March
16, 1987.
- **Delmarva Power and Light Company**
Delaware Public Service Commission, PSC Regulation Docket No. 14 (Concerning Gas and
Electric Fuel Adjustment Clauses), December 1, 1986 and December 21, 1987.
- **Southern California Edison Company**
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August 26-28, 1986.
- **Florida Power and Light Company**
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1986.
- **Jersey Central Power and Light Company**
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- **Florida Power and Light Company**
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- **Commonwealth Edison Company**
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June 23, 1986.
- **Gulf States Utilities Company**
Federal Energy Regulatory Commission, Docket No. ER85-538-001, January 6, 1986 and April
25, 1986.
- **Arizona Public Service Company**
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- **Eastern Utility Associates Power Corporation**
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- **Southern California Edison Company**
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August 20, 1985.
- **Baltimore Gas and Electric Company**
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- **Central Vermont Public Service Corporation**
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- **Central and South West Services, Inc.**
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- **Gulf States Utilities Company**
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- **Gulf States Utilities Company**
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- **Gulf States Utilities Company**
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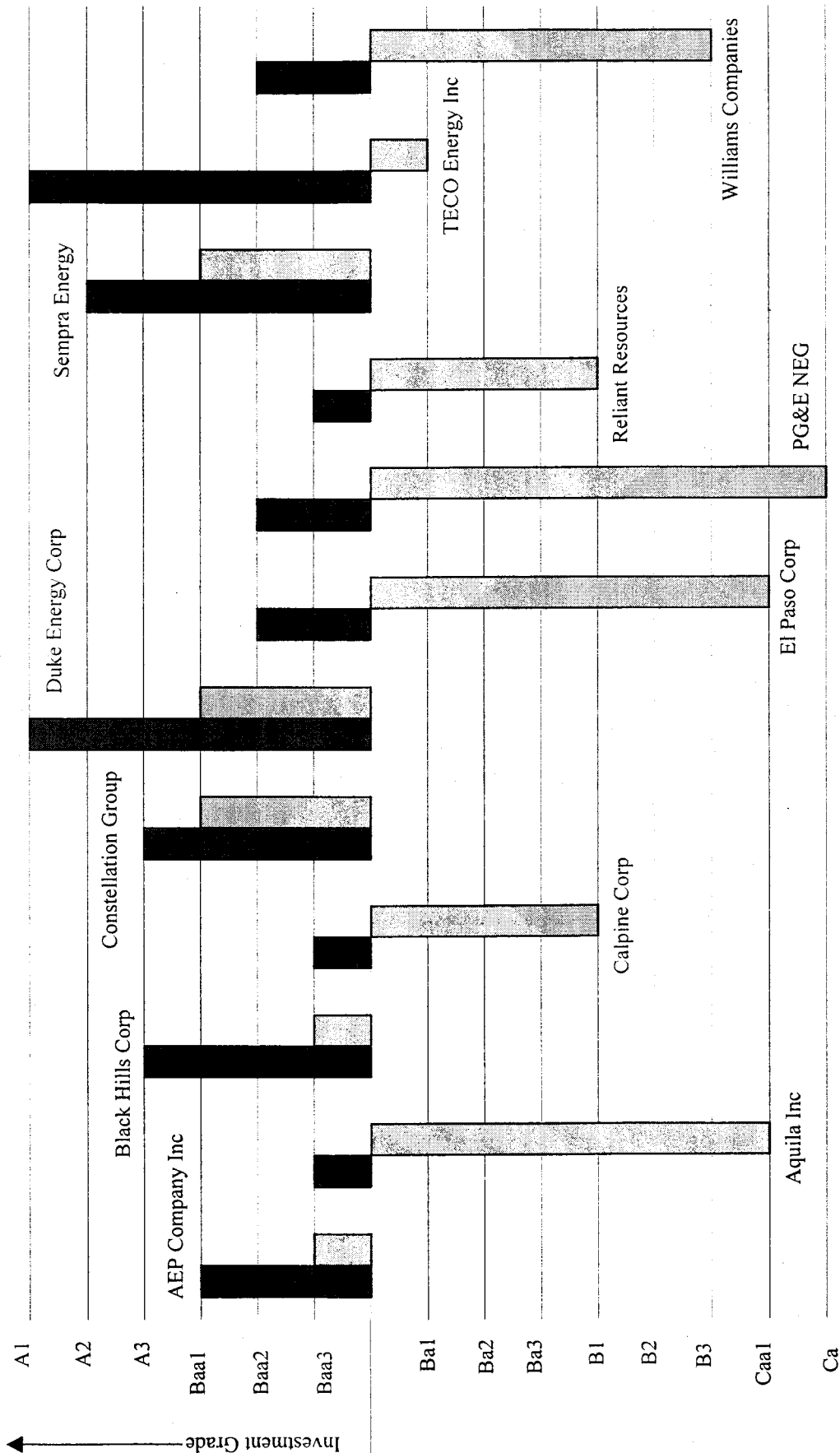
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■ 2001 ■ 2003

Sources: Companies' Press Releases and Moodys.com

Notes:

1. In 2001, UtiliCorp United owned 80% of Aquila Inc; The 2001 rating is for UtiliCorp United.
2. Long-Term Senior Implied Rating is used for Reliant's current rating.

Testimony
of
Alan Propper

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DIRECT TESTIMONY OF ALAN PROPPER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-__

June 27, 2003

Table of Contents

TABLE OF CONTENTS.....	i
I. INTRODUCTION AND SUMMARY	1
II. COST-OF-SERVICE.....	2
III. SPECIALLY HANDLED COST ITEMS	7
IV. "G" SCHEDULES	11
V. RATE DESIGN.....	13
VI. TRANSMISSION COST ADJUSTMENT CLAUSE.....	18
VII. RECOVERY OF OTHER COST ELEMENTS	21
VIII. RESIDENTIAL RATE SCHEDULES	22
IX. GENERAL SERVICE RATE SCHEDULES.....	27
X. CLASSIFIED SERVICE RATE SCHEDULES.....	30
XI. DIRECT ACCESS RATES	34
XII. "H" SCHEDULES	34
XIII. CONCLUSIONS.....	37
STATEMENT OF QUALIFICATIONS	Appendix A
SCHEDULE GJ	Attachment AP-1
SCHEDULE GE1.....	Attachment AP-2
SCHEDULE GE2.....	Attachment AP-3
SCHEDULE GE3.....	Attachment AP-4

1 **DIRECT TESTIMONY OF ALAN PROPPER**
2 **ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
3 **(Docket No. E-01345A-03-)**

4 I. **INTRODUCTION AND SUMMARY**

5 Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

6 A. My name is Alan Propper. My business address is 400 North Fifth Street, Phoenix,
7 Arizona 85004.

8 Q. **BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?**

9 A. I am employed by Arizona Public Service Company ("APS" or "Company") as
10 Director of Pricing. I am responsible for establishing and administrating APS
11 tariffs and contract provisions that are under the jurisdiction of the Arizona
12 Corporation Commission ("ACC" or "Commission") or the Federal Energy
13 Regulatory Commission ("FERC").
14

15 Q. **WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND
16 BUSINESS EXPERIENCE?**

17 A. My background and experience are set forth in Appendix A to this testimony.

18 Q. **WERE THIS TESTIMONY AND THE ACCOMPANYING
19 ATTACHMENTS PREPARED BY YOU OR UNDER YOUR DIRECTION?**

20 A. Yes, they were.

21 Q. **ARE YOU SPONSORING ANY STANDARD FILING REQUIREMENTS
22 ("SFR") SCHEDULES?**

23 A. Yes. I am sponsoring required SFR Schedules G, and H, and portions of SFR
24 Schedules B-1, B-2, C-1, and C-2, as well as the rate schedules portion of APS'
25 retail tariff. Although not specifically required by the SFR, I am also sponsoring
26 some additional schedules that have been designated as Schedule GJ (Attachment

1 AP-1), Schedule GE1 (Attachment AP-2), Schedule GE2 (Attachment AP-3), and
2 Schedule GE3 (Attachment AP-4) and are attached to my testimony.

3
4 **Q. WOULD YOU SUMMARIZE YOUR TESTIMONY?**

5 A. My testimony addresses two general areas. The first area discusses the cost-of-
6 service study prepared to Functionalize, Classify, and then Allocate test year costs
7 and revenues first between wholesale and retail customers and then to the various
8 classes of retail service. It is this cost allocation study that allows me to determine
9 the rate of return produced by each class and subclass of customer, as well as the
10 unit costs needed to be expended to provide service to each customer grouping.
11 The second area discusses the rates and related service provisions being proposed
12 to recover the costs of providing service to our customers.

13
14 **II. COST-OF-SERVICE**

15 **Q. WAS AN EMBEDDED CLASS COST-OF-SERVICE STUDY USED IN THE
16 DEVELOPMENT OF APS' PROPOSED RATES?**

17 A. Yes. APS' proposed rates are based on an embedded and fully allocated cost-of-
18 service study, with calendar year 2002 as the test period, as a major input for
19 designing the proposed rates. The study results provided both rates of return for
20 the customer classes as well as a Functionalization, Classification, and Allocation
21 of costs.

22 **Q. WAS THE USE OF A 2002 TEST YEAR SUITABLE FOR THIS COST-OF-
23 SERVICE STUDY?**

24 A. Yes. A test year utilizing 2002 data provides the most recent calendar year
25 financial and operational information, and is consistent with the Company's
26 revenue requirements. Therefore, I believe it is appropriate to be used as the basis
for performing an accurate cost-of-service analysis. Although a future test year is

1 more reflective of the period in which the proposed rates will be in effect, such a
2 future test period is not generally used in Arizona. However, the Company's
3 analysis does include a number of pro forma adjustments to the 2002 test year to
4 reflect known changes and to better match the costs and revenues with the period
5 in which the proposed rates will be in effect, as well as other adjustments to
6 normalize the test period.

7
8 **Q. WHAT DO YOU MEAN BY NORMALIZING THE 2002 TEST YEAR INFORMATION?**

9 A. Normalization refers to eliminating the effect of conditions or situations that
10 would not ordinarily occur or be expected to occur in a normal test year, or that
11 recur periodically but should be averaged out over a period of years. The purpose
12 of normalization is to produce a test year that will be generally representative of
13 conditions that would exist during the period in which the proposed rates would be
14 in effect. For example, if APS experienced some unusual expense during the test
15 year, such as inordinately high storm damage, an adjustment to reflect more
16 normal conditions would be appropriate.

17
18 **Q. HOW DO YOU TREAT PRO FORMA AND NORMALIZATION ADJUSTMENTS TO THE TEST YEAR IN YOUR COST-OF-SERVICE STUDY?**

19 A. APS witness Donald G. Robinson's testimony sponsors a number of pro forma
20 adjustments that were incorporated into the adjusted 2002 test year cost-of-service
21 study. Mr. Robinson's Attachments DGR-4 and DGR-5 list, by rate base and
22 expense category, the monetized amount of each proposed pro forma adjustment.
23 These amounts were then Functionalized, Classified, and Allocated to the
24 appropriate retail and wholesale customer classes as part of the process in
25 performing the cost-of-service study. Please note that in Mr. Robinson's
26

1 testimony, he distinguishes between several types of pro forma adjustments, in
2 addition to normalizing adjustments, depending on the basis for making the
3 adjustment. However, for purposes of performing a test period cost-of-service
4 analysis, whether an adjustment is appropriate because of normalization or as a
5 result of a change that has occurred or will occur is not relevant, and thus I refer to
6 all test year adjustments generically as pro forma adjustments. The adjusted 2002
7 test year cost-of-service study reflects all the proposed pro forma adjustments.

8
9 **Q. WOULD YOU DISCUSS THE DEVELOPMENT OF THE EMBEDDED
COST ALLOCATION STUDY?**

10 A. This study was prepared using industry accepted cost-of-service principles of
11 Functionalization, Classification, and Allocation and is generally consistent with
12 historical APS practices.

13 “Functionalization” refers to the process of attributing a particular Rate Base or
14 Expense item to a particular function, namely Production, Transmission, or
15 Distribution, in the provision of electric service. An easy and obvious example is
16 the assignment of the costs of building and operating one of the Company’s power
17 plants to the Production function.

18
19 “Classification” refers to the process of determining the factor or factors that
20 compel the magnitude of the cost. For example, if a cost is driven by the amount
21 of energy consumed, it is classified as Energy; if a cost is driven by the rate at
22 which energy is consumed, it is classified as Demand; or if a cost is driven by the
23 number of customers taking service on the APS system irrespective of either
24 demand or energy utilized, it is classified as Customer.

1 "Allocation" occurs once a cost has been functionalized and classified. This is the
2 process in which allocation factors are applied to spread the costs to particular
3 jurisdictions, customer classes, and rate schedules. A simple example is the
4 allocation of energy related costs by kilowatt-hour ("kWh") consumption.

5 In this study, the numerous Expense and Rate Base items that comprise APS' costs
6 were grouped into major categories, such as Plant in Service or Operating &
7 Maintenance Expense. Each of these categories was first functionalized into
8 Production, Transmission, or Distribution related costs, then classified as Demand,
9 Energy, or Customer related. Allocation factors based on kilowatts, kilowatt-
10 hours, and number of customers were then developed so that allocations of the
11 functionalized and classified costs could be made to the federal and state
12 jurisdictions and to the various retail customer classes and sub-classes. When
13 necessary, procedures were used to reflect unusual or changing circumstances, as
14 discussed later in my testimony.

15
16 **Q. WHAT BASIS IS USED TO ALLOCATE FUNCTIONALIZED COSTS**
17 **BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?**

18 A. Production related and Transmission related assets, and their associated costs, are
19 generally designed and built to enable the Company to meet its system peak load.
20 Correspondingly, they are allocated on the basis of the average of the system peak
21 demands occurring in the months of June, July, August, and September ("4CP").
22 Distribution plant, unlike Production and Transmission plant is generally designed
23 to meet a customer class' peak load, which may or may not be coincident with the
24 system peak load. Thus, allocations of costs related to Distribution substations
25 and primary Distribution lines are made on the basis of non-coincident peak loads
26 ("NCP"). Allocations of costs related to Distribution transformers and secondary

1 Distribution lines are made on the basis of the summation of the individual peak
2 loads or demands of all customers within a particular customer class ("ΣNCP").

3
4 **Q. WHAT IS THE BASIS OF THE "ALL OTHER" OR NON-JURISDICTION
SEGMENT OF YOUR COST-OF-SERVICE STUDY?**

5 A. The "All Other" segment, which appears as a separate column in the cost-of-
6 service study, represents the Rate Base, Expenses, and Revenues associated with
7 service to long-term firm FERC jurisdictional resale customers that APS serves, as
8 well as firm wheeling services APS provides to a number of FERC jurisdictional
9 entities. Since APS utilizes Company facilities in order to fulfill these obligations,
10 I have allocated a portion of APS Production, Transmission, and Distribution
11 facilities to these non-jurisdictional customers in the same manner as I would to
12 our classes of retail jurisdictional customers in preparing this cost-of-service
13 study.

14
15 **Q. WOULD YOU EXPLAIN THE USE OF REVENUE CREDITS IN THE
COST-OF-SERVICE STUDY?**

16 A. In addition to the transactions described for inclusion in the All Other column
17 depicted in the cost-of-service study, APS makes off-system sales to third-party
18 entities. In making such off-system transactions, APS resources may be utilized.
19 In order to be certain that the benefits of such transactions flow through to our
20 retail customers, the revenues derived from these transactions, which more than
21 cover the incremental costs associated with producing or acquiring the required
22 energy, are allocated to all customers. Thus, the margin or profit that APS realizes
23 from such non-retail transactions is attributed to each class through the Revenue
24 Credit, which benefits all customers by lowering their otherwise determined
25 revenue requirement.

1 Also treated as Revenue Credits are the somewhat unpredictable and non-firm
2 short-term Transmission for Others transactions, and a number of small items such
3 as Rent from Electric Property, Forfeited Discounts, Miscellaneous Service
4 Revenues, sales to Rate E-36 customers, and Other Electric Revenues.
5

6 **III. SPECIALLY HANDLED COST ITEMS**

7 **Q. HAVE ANY NEW OR SPECIALIZED PROCEDURES BEEN USED IN**
8 **PERFORMING THIS COST ALLOCATION STUDY?**

9 A. Yes. As a result of FERC initiatives to foster wholesale competition, FERC's
10 Transmission pricing principles, and recent FERC decisions affecting APS, some
11 degree of jurisdictional authority over the Transmission component of bundled
12 retail rates in states having mandated retail access programs has been claimed by
13 FERC. This circumstance has an impact on the Transmission related costs within
14 the parameters of a cost-of-service study, and therefore Transmission related costs
15 were treated in a different manner than has been done historically.

16 **Q. WOULD YOU EXPLAIN HOW TRANSMISSION COSTS WERE**
17 **TREATED IN THE COST-OF-SERVICE STUDY?**

18 A. A November 30, 2000 FERC Order requires APS to acquire Transmission related
19 services used to supply electric power and energy to Scheduling Coordinators for
20 APS' Standard Offer retail customers under the provisions of APS' own Open
21 Access Transmission Tariff ("OATT"). The requirement for having a Scheduling
22 Coordinator is stated in the Protocols of the Arizona Independent Scheduling
23 Administrator ("AISA"), and is further supported in the Commission's
24 Competition Rules. Thus, from a cost allocation perspective, the revenue
25 requirement for such Transmission services is treated as an expense derived from
26 the FERC jurisdictional rates expressed in our OATT.

1 Specifically, APS' retail merchant function, which serves as the Scheduling
2 Coordinator for Standard Offer customers and is responsible for generating or
3 purchasing power for APS' Standard Offer retail customers, has been required to
4 pay APS' OATT rates for Transmission and Ancillary Services needed to deliver
5 electric power and energy to these APS retail customers. Those dollars were
6 booked as both Transmission revenue and as an offsetting Transmission expense
7 during the test period.

8
9 **Q. HOW DID YOU DEVELOP COSTS FOR THE TRANSMISSION
FUNCTION IN THE COST-OF-SERVICE STUDY?**

10 A. For purposes of this cost-of-service study, I first computed Transmission related
11 Rate Base and Expense for the test period. This was accomplished by first
12 performing a complete unadjusted 2002 cost-of-service study which included
13 identifying Production, Transmission, and Distribution costs using the traditional
14 cost-of-service methodologies I discussed previously. From this study, total
15 Transmission costs, both Rate Base and Expenses, were isolated and used as the
16 basis for determining how much of the Company's costs were related to providing
17 Transmission services. Finally, these Transmission related costs were removed
18 from the cost-of-service study via pro forma adjustments, as indicated in Mr.
19 Robinson's testimony and attachments.

20
21 Since total Transmission costs are being treated as an operating expense for
22 purposes of this study, this expense was developed by aggregating the following
23 transactions: 1) retail related Transmission expenses were calculated by
24 multiplying adjusted test year retail billing determinants by the applicable
25 Transmission rates in Part IV of APS' OATT; 2) test year revenues from pre-
26 OATT firm wholesale wheeling transactions were treated as an expense; and 3)

1 the test period billing determinants for post-OATT firm wheeling transactions
2 were multiplied by APS' OATT rate for firm point-to-point Transmission service
3 of \$1.43/kW/month. These OATT expense items were then included in the cost-
4 of-service study via a pro forma adjustment. I will discuss the proposed recovery
5 of Transmission related costs in the Rate Design section of my testimony.

6 **Q. ARE ANCILLARY SERVICES TREATED IN A SIMILAR MANNER?**

7 **A.** Yes. FERC views Ancillary Services as Transmission related services, and
8 therefore a pro forma adjustment was made to remove associated rate base and
9 expense items from the cost-of-service study. Since several of the six Ancillary
10 Services are Production related, for cost-of-service purposes, I first identified
11 which APS generating units were used in providing a specific Ancillary Service. I
12 then determined what portion of the total MWh produced during the test period by
13 that unit was for that specific Ancillary Service. This percentage was then used as
14 the basis for allocating that portion of a particular unit's test period costs to that
15 specific Ancillary Service.

16
17 Once the appropriate Production related cost associated with each pertinent
18 Ancillary Service was determined, it formed the basis of the Ancillary Services
19 component of the Transmission pro forma adjustments discussed above. Note that
20 the proposed Transmission pro forma adjustments are comprised of two
21 components, Transmission and Ancillary Services. The amount of this Ancillary
22 Services component was then subtracted from Production related costs that were
23 to be allocated to the various customer classes. Consistent with the treatment of
24 Transmission costs as an expense for purposes of the cost-of-service study,
25 Ancillary Service related costs are treated similarly. I derived the applicable
26 Ancillary Service expense assigned to retail customers by multiplying the adjusted

1 2002 test period retail billing determinants times the applicable rates for Ancillary
2 Services contained in Part IV of APS' OATT.

3 Although "Must Run" is not specifically considered a FERC Ancillary Service,
4 FERC nevertheless considers it a Transmission related service and has also
5 asserted its jurisdiction over Must Run charges. In developing the cost-of-service
6 study, I specifically excluded the appropriate costs associated with Must Run so
7 they would not be included in our Standard Offer retail rates. At such time the
8 Company elects to assess and collect specific Must Run charges, we will be
9 required to modify our OATT to include these charges, and make the appropriate
10 filing with FERC pursuant to their Order in Docket No. ER01-173-000, issued
11 November 30, 2000.
12

13 **Q. DOES YOUR COST ALLOCATION STUDY CONTAIN ANY TERMS OR**
14 **ITEMS THAT HAVE NOT TRADITIONALLY BEEN DIRECTLY**
15 **ADDRESSED IN COST-OF-SERVICE?**

16 A. Yes. The study reflects treatment of System Benefits and Regulatory Assets.

17 **Q. WOULD YOU EXPLAIN WHAT IS MEANT BY SYSTEM BENEFITS?**

18 A. System Benefits refer to the costs associated with such items as renewable
19 resources, demand side management, nuclear plant decommissioning, nuclear fuel
20 disposal, customer education, and other items that may be included in rates, as
21 specified by the ACC. For the purposes of this cost allocation study, System
22 Benefits costs have been separately accumulated and unbundled so they can be
23 identified for rate design purposes.

24 **Q. WOULD YOU EXPLAIN WHAT IS MEANT BY REGULATORY ASSETS?**

25 A. Regulatory Assets are expenses incurred by APS on projects, equipment, and
26 financial obligations for the benefit of its customers that have not as yet been paid

1 for by its customers. Pursuant to ACC Decision Nos. 59601 and 61973, the ACC
2 authorized the collection of certain of these expenses from customers through
3 electric rates over an extended period of time, thereby smoothing out their
4 recovery in customer bills. Examples of Regulatory Assets are deferred income
5 tax payments, accrued coal mine reclamation costs, and deferred financing costs
6 for specific generation units. For purposes of this cost allocation study,
7 Regulatory Assets have been separately identified as a stand-alone function and
8 have not been assigned to Production, Transmission, or Distribution.

9
10 **Q. HOW HAVE YOU HANDLED FRANCHISE FEES?**

11 A. For the purpose of the cost-of-service study, as well as rate design, expenses
12 associated with Franchise Fees and associated revenues have been excluded from
13 the cost-of-service study and will be treated as a rate surcharge or an addition to be
14 passed through to our customers, much the same as Sales Tax. This is discussed
15 more fully in my testimony under Rate Design.

16 **Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND RATE OF
17 RETURN BASED ON THE 2002 ADJUSTED TEST YEAR?**

18 A. Yes. In addition to establishing the Production, Transmission, and Distribution
19 functions and the Demand, Energy, and Customer classifications for each class of
20 retail business, the rate of return for each class under test year and proposed rates
21 appear in the SFR "G" Schedules associated with this rate application.

22 **IV. "G" SCHEDULES**

23 **Q. MR. PROPPER, WOULD YOU DESCRIBE THE SFR "G" SCHEDULES?**

24 A. Yes. The following is a summary of these Schedules:

- 25
 - SFR Schedule G-1 shows the rate-of-return at existing rates by customer

26

1 class, based on the adjusted 2002 test year cost-of-service study.

- 2 • SFR Schedule G-2 is similar to Schedule G-1 except this Schedule reflects
- 3 returns by class that would result under APS' proposed rates in this
- 4 proceeding.
- 5 • SFR Schedule G-3 shows the \$ and % amount of adjusted Original Cost
- 6 Less Depreciation ("OCLD") Rate Base costs allocated to each retail
- 7 customer class.
- 8 • SFR Schedule G-4 shows the amount of operating Expenses allocated to
- 9 each retail customer class.
- 10 • SFR Schedule G-5 shows the \$ amount of functionalized adjusted Rate
- 11 Base allocated to ACC jurisdictional customers.
- 12 • SFR Schedule G-6 shows the amount of functionalized adjusted operating
- 13 Expense allocated to the ACC jurisdictional customers.
- 14 • SFR Schedule G-7 lists all applicable allocation factors used in preparing
- 15 the 2002 test year cost-of-service study.

16
17 **Q. DO YOU HAVE ANY ADDITIONAL SCHEDULES RELATED TO THE**
18 **COST-OF-SERVICE STUDY THAT YOU ARE SPONSORING?**

19 A. Yes. The following filed additional Schedules relate to the study:

- 20 • Schedule GJ is a summary of the cost-of-service study showing the
- 21 jurisdictional separation of Rate Base costs, Revenues, and operating
- 22 Expenses.
- 23 • Schedule GE1 is a summary of the cost-of-service study showing, by retail
- 24 customer class, the allocation of total ACC allocated Rate Base costs,
- 25 Revenues, and operating Expenses and the rate-of-return for each major
- 26 customer class.
- Schedule GE2 is a summary of the cost-of-service study showing, by each

1 General Service subclass, the allocation of Rate Base costs, Revenues, and
2 operating Expenses and the rate-of-return.

- 3 • Schedule GE3 is a summary cost-of-service study showing, by each
4 Residential subclass, the allocation of Rate Base costs, Revenues, and
5 operating Expenses and the rate-of-return.

6
7 **Q. BASED ON THE RESULTS OF YOUR ADJUSTED TEST YEAR 2002**
8 **COST-OF-SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU**
9 **MADE?**

10 A. I believe it is apparent from the "G", GJ, and GE Schedules that there are
11 significant disparities in the rates of return that the different customer classes are
12 providing to the Company. In addition, but less apparent from the summaries, is
13 my conclusion that the rate designs themselves, separate and apart from their
14 individual levels, do not fully reflect the Demand, Energy, and Customer unit
15 costs relationships as would be dictated by strictly cost based rate design. These
16 conclusions need to be considered as one of the inputs for the proposed rate
17 designs.

18 **V. RATE DESIGN**

19 **Q. WERE APS' PROPOSED RATES DEVELOPED BY YOU OR UNDER**
20 **YOUR SUPERVISION?**

21 A. Yes, my department personnel and I developed the proposed rates and schedules.
22 However, we did receive input from our Customer Service department in
23 developing the proposed rate schedules.

24 **Q. WOULD YOU DESCRIBE THE OVERALL OBJECTIVES OF THE**
25 **PROPOSED RATE DESIGNS?**

26 A. In developing our proposed rate schedules, we had several objectives in mind.
First, the proposed rates were developed to meet APS' revenue requirement.

1 Second, it was our desire to improve cost tracking, both as to rate level and design
2 of the pricing components, of our various rates. Third, we endeavored to better
3 unbundle the rates in conformance with the objectives established by the ACC in
4 the Commission's Electric Competition Rules.

5 **Q. WOULD YOU EXPLAIN WHAT YOU MEAN BY "IMPROVE THE COST**
6 **TRACKING OF THE VARIOUS ELEMENTS OF OUR RATES?"**

7 A. It has been many years since APS has revised the basic structure of its retail rates.
8 The more recent rate changes have generally been made on the basis of "across the
9 board" percentage changes as a result of rate case settlements. This has resulted in
10 some rate distortions that have taken our rates away from tracking costs, both as to
11 rate level and rate design. The process of unbundling our retail rates also
12 identified instances in which our rates were obviously not fully following costs.
13 Our proposed rates address, at least to the degree I believe practical, this concern.
14 As will be discussed, this concern was addressed through redesign of the rates
15 themselves, and not by varying the proposed overall percentage increase to each of
16 the major customer classes.

17 **Q. WOULD YOU DESCRIBE THE PROCESS USED TO DEVELOP THE**
18 **PROPOSED RATES?**

19 A. The starting point in the rate design process is the cost-of-service study discussed
20 earlier in my testimony. The cost-of-service study allocates the costs of providing
21 service to each of the major classes of customers, as well as various sub-classes
22 and rate schedules. If the cost-of-service study was the only determinant for
23 setting rates, each rate classification would recover APS' proposed rate of return
24 and all rate schedules would be expressed in the form of unit costs and expressed
25 as Demand Charges, Energy Charges, and Customer Charges. However, many
26 other considerations were taken into account in designing the proposed rates,

1 which resulted in individual rate schedules that differ from the overall proposed
2 rate of return and rate designs that differ in appearance and application.

3
4 **Q. OTHER THAN THE COST-OF-SERVICE STUDY, WHAT OTHER**
5 **FACTORS WERE CONSIDERED WHEN DESIGNING THE PROPOSED**
6 **RATES?**

7 A. We considered several other factors. Among the most important were rate
8 stability and continuity. For this reason, the major classes of customers—
9 Residential, General Service, Irrigation, Street Lighting, and Dusk to Dawn—have
10 each been given a percentage increase that is approximately the same as the
11 overall requested increase. In addition, the individual rate schedules have been
12 designed to depart from strict cost-of-service adherence as necessary, so that
13 differences in the increases that individual customers will experience will be
14 moderated to the extent reasonable. An additional consideration in developing the
15 proposed rate schedules was customer understandability and ease of
16 administration. In other words, we attempted to simplify the specific rates and the
17 presentation of the tariff in general. Consideration of these factors is in
18 conformance with the traditional or classical aspects of rate design.

19 **Q. HAVE THE PROPOSED RATES BEEN UNBUNDLED TO SHOW THE**
20 **INDIVIDUAL COMPONENTS OF COST RECOVERY?**

21 A. Yes, to the degree practical or possible. Moving from bundled rate schedules to
22 unbundled and more cost-based rate designs represents a significant change from
23 current and previous rates. We attempted to mitigate the problems and confusion
24 related to this transition to the unbundled rate formats by carefully considering the
25 content and format of the rate schedules, as well as the expected appearance of the
26 resulting bills.

1 Q. **WAS THE COST-OF-SERVICE STUDY USED IN DEVELOPING THE**
2 **PRICING OF REVENUE CYCLE SERVICES IN THE UNBUNDLED**
3 **PROPOSED RATES?**

4 A. Revenue Cycle Services include metering, meter reading, and billing which, under
5 certain circumstances as approved by the Commission, can be rendered to the
6 customer by a provider other than APS. In such instances, when a customer elects
7 an alternative provider, a cost (or price credit) must be developed so that APS is
8 not charging the customer for these services. The cost-of-service study was used
9 to develop pricing for these unbundled Revenue Cycle Services costs for each
10 unbundled rate schedule.

11 Q. **DOES THIS MEAN THAT APS IS WILLING TO IGNORE THE LOWER**
12 **DECREMENTAL COST OF REVENUE CYCLE SERVICES WHEN**
13 **PROVIDING A CREDIT TO A CUSTOMER WHO TAKES SUCH**
14 **SERVICES FROM A PROVIDER OTHER THAN APS?**

15 A. Yes, but only for purposes of this rate case. The decremental cost of Revenue
16 Cycle Services, such as billing, is the actual cost saved by APS if an alternative
17 provider, such as a competitive Electric Service Provider ("ESP"), provides that
18 service to an APS customer. In the short run and for small increments of
19 customers, this decremental cost is very low. In the example of meter reading, it
20 amounts to only the cost of one stop in a meter reader's entire route.

21 Using the embedded cost-of-service study for establishing the cost savings to APS,
22 as is being proposed, does overstate these costs and therefore the price credit.
23 However, given the general lack of interest in retail Direct Access to date and
24 virtually no recent interest by ESPs in providing specific Revenue Cycle Services,
25 the burden the higher credit would impose on other APS customers is minimal. I
26 do not believe the dollar amounts involved to be great enough to justify preparing
the detailed studies needed to determine the decremental costs, though such an

1 approach would philosophically be the preferred method. It is quite possible that
2 the Company may wish to revisit this matter in the next rate case if our experience
3 with others providing such services warrants a reexamination.

4
5 **Q. DID UNBUNDLING THE RATES AND, IN PARTICULAR, REVENUE
CYCLE SERVICES IMPACT BASIC SERVICE CHARGES?**

6 A. Yes. Revenue Cycle Services are fixed Customer related costs that should be
7 collected in the fixed Basic Service Charge component of a rate. Including
8 recovery of even a portion of these costs through the variable Energy or Demand
9 components of a rate not only unduly varies from cost tracking and causation, but
10 also creates major design, administrative, and customer equity problems. This
11 situation becomes most noticeable when establishing Direct Access rates that are
12 to correspond to the unbundled Standard Offer rates. For these reasons, the Basic
13 Service Charge of each rate was adjusted to be certain that, at the very least, no
14 less than Revenue Cycle Services costs would be recovered in this charge.

15 In addition, it should be noted that the Basic Service Charge for many rates will
16 now be stated as a daily charge. This is for the purpose of recognizing that the
17 number of days in a billing month changes from month to month, and to facilitate
18 billing and avoid proration when customers do not receive service from the
19 Company or service on the same rate for the full billing month.

20
21 **Q. WOULD YOU DESCRIBE THE RATE DESIGN CHANGES YOU HAVE
22 MADE WITH REGARD TO THE RECOVERY OF TRANSMISSION
RELATED COSTS?**

23 A. For the reasons I mentioned in my discussion of the cost-of-service study, we have
24 changed how we treat Transmission costs, as well as Ancillary Services and Must
25 Run, when compared to our previous traditional cost-of-service studies. That
26 portion of the FERC jurisdictional Transmission cost that will be passed on to

1 retail customers is based on the average charge incurred by the Scheduling
2 Coordinator for the APS retail load. We are proposing that a Transmission Cost
3 Adjustment Clause, similar to the Power Supply Adjustment Clause ("PSA") that
4 APS proposed last year, be instituted. This will enable us to pass on the
5 Transmission costs incurred to supply electric power to the retail customers in a
6 timely manner and on a dollar for dollar basis. Once a Regional Transmission
7 Operator ("RTO") or its equivalent is operating, APS' Scheduling Coordinator
8 will become a purchaser of Transmission service from the RTO, and the rates and
9 proposed adjuster will pass on FERC regulated RTO charges as an expense for
10 Transmission service.

11
12 VI. TRANSMISSION COST ADJUSTMENT CLAUSE

13 Q. **WOULD YOU DESCRIBE THE PROPOSED TRANSMISSION COST**
14 **ADJUSTMENT CLAUSE?**

15 A. The clause appears as Rate Schedule TCA-1. As with any such adjustment clause,
16 it is designed to track changes occurring in a specific cost, whose base amount is
17 included in the retail rates. In this particular instance, the clause relates to specific
18 costs incurred by the Scheduling Coordinator for procuring Transmission related
19 services for retail customers under APS' or some other Transmission provider's
20 OATT or contract.

21 Each of our proposed Standard Offer rates includes a base Transmission charge,
22 reflecting the Transmission related expenses I previously described. The proposed
23 Transmission Cost Adjustment ("TCA") factor will track the actual incurred costs
24 of providing these Transmission related services compared to the cost inherent in
25 base retail rates. The TCA factor will be credited or debited to customers' bills
26

1 each month as a per kWh Energy charge. The factor will be the same for all
2 affected Standard Offer customers and will be adjusted once each year.

3 The TCA methodology consists of four components:

- 4 • A base level Transmission related charge component inherent in the
- 5 Standard Offer retail rates,
- 6 • A monthly Transmission Cost Component Factor ("TCCF") charged to
- 7 customers,
- 8 • A Balancing Account, and
- 9 • An Amortization Charge that may be implemented to reduce the size of the
- 10 Balancing Account.

11
12 **Q. WILL THE TCA APPLY TO DIRECT ACCESS CUSTOMERS?**

13 A. No, but that does not mean Direct Access customers will not pay for these costs.
14 The Scheduling Coordinator for a Direct Access customer will be directly charged
15 the OATT charge by APS under its FERC tariff. The extent and manner by which
16 such OATT charge is passed along to the Direct Access customer will be
17 determined by the load serving ESP's contract with its customer.

18 **Q. WOULD YOU DESCRIBE HOW THE TCCF WILL BE COMPUTED?**

19 A. Basically, the TCCF is computed by comparing the twelve-month Transmission
20 cost to the base Transmission charge. For example, if the twelve-month actual
21 Transmission related average cost is 5.0 mills per kWh and the base Transmission
22 charge is 4.7 mills per kWh, the TCCF would be 0.3 mills per kWh. The TCCF
23 can be positive or negative.
24
25
26

1 **Q. WOULD YOU PLEASE DESCRIBE THE PURPOSE OF THE**
2 **BALANCING ACCOUNT?**

3 A. The Balancing Account accumulates dollars associated with under-collection or
4 over-collection from the application of the TCA. The TCCF will be adjusted once
5 each year after the final bills for Transmission service for the previous calendar
6 year are received. The adjusted TCCF will then be applied for the next 12 months.
7 Thus, there is a slight mismatch between the time periods of cost incurrence and
8 revenue collection. From time to time, APS may make a filing with the ACC to
9 obtain approval to amortize any TCA account balance and reset the Balancing
10 Account to zero. It is intended that interest will be accrued based on the three-
11 month commercial paper rate. The interest will be credited for both positive and
12 negative Balancing Account accumulations.

13 Specific details regarding the operation and administration of the TCA will be set
14 forth in a Plan for Administration to be approved by this Commission subsequent
15 to adoption of the TCA.

16 **Q. WHAT ACC ACTIONS WILL BE REQUIRED TO IMPLEMENT**
17 **CHANGES ONCE THE TCA MECHANISM IS APPROVED?**

18 A. APS will make informational filings with the ACC annually. These filings will
19 include the calculations required for developing an updated TCCF for the
20 subsequent year, invoices for Transmission and Ancillary services rendered to the
21 APS retail Scheduling Coordinator, and the Balancing Account calculations. Must
22 Run information will also be included when applicable. Each filing will include a
23 revised tariff sheet indicating the revised TCCF, which would be effective upon
24 filing or on such date as is indicated in the filing. Formal Commission action
25 would only be required if a filing is made by APS requesting establishment of or
26 revision to the Amortization Charge.

1 VII. RECOVERY OF OTHER COST ELEMENTS

2 Q. **WOULD YOU PLEASE DESCRIBE HOW FRANCHISE FEES PAID TO**
3 **MUNICIPALITIES WILL BE RECOVERED?**

4 A. We are proposing that these Franchise Fees be removed from base rates.
5 Franchise Fees would instead be collected via a separate charge on customers'
6 bills, similar to the method used to collect Sales Tax.

7 Q. **WHY ARE YOU PROPOSING THIS CHANGE TO THE FRANCHISE FEE**
8 **COLLECTION METHOD?**

9 A. First, it brings us in line with the rest of the utility industry and, in particular, other
10 electric utilities in Arizona. Second, it is simply a fairer method. Franchise Fees
11 are effectively a tax on APS levied by the municipalities in which we serve.
12 Currently, Franchise Fees are recovered from all customers through base rates,
13 regardless of the political subdivision in which they reside. Under our proposed
14 method, customers in Phoenix will only pay the costs associated with the Phoenix
15 Franchise Fee, Flagstaff ratepayers will pay the Flagstaff Franchise Fee, and so
16 forth. Those customers outside of municipal franchise areas will no longer pay for
17 Franchise Fees through the base rates. Simply stated, our proposed method assures
18 the correct and fair relationship between Franchise Fees imposed by municipalities
19 and collection of these fees from the retail customers residing in the respective
20 municipalities.

21 Q. **ARE THERE ANY OTHER COST ELEMENTS THAT WOULD RECEIVE**
22 **RECOVERY TREATMENT OUTSIDE OF THE BASE RATES?**

23 A. Yes. In addition to costs to be recovered through the PSA and the Transmission
24 Adjuster, Franchise Fees, Regulatory Assessments, and Sales Tax, there are those
25 costs associated with the Environmental Portfolio Surcharge as set forth in Rate
26 Schedule EPS-1, the Competition Rules Compliance Charge as set forth in Rate

1 Schedule CRCC-1, the Returning Customer Direct Assignment Charge as set forth
2 in Rate Schedule RCDAC-1, and the System Benefits Adjustment Charge as set
3 forth in Rate Schedule SBAC-1.

4 **Q. HAVE YOU ESTABLISHED THE BASE CHARGES FOR THE VARIOUS**
5 **SURCHARGES OR ADJUSTMENT CLAUSES?**

6 A. Yes. Based on the cost-of-service study, bases have been established for the PSA,
7 CRCC, and the TCA, and are stated in the appropriate rate schedules. The
8 mechanisms for charges under the RCDAC and the SBAC are to be established in
9 Docket No. E-01324A-02-0403.

10 **Q. WOULD YOU DISCUSS THE NOTICE THAT APS WOULD PROVIDE**
11 **TO CUSTOMERS OF CHANGES IN THE FACTORS AND CHARGES**
12 **RELATED TO THE PSA?**

13 A. Yes. Although a decision has not yet been made in the docket for the PSA, APS
14 said it would discuss in this rate case the notice to be provided to customers for
15 changes in the factors and charges related to the PSA. Notice for changes to the
16 Power Cost Component Factors, which will be adjusted semiannually, or in cases
17 where the Balancing Account is amortized and reset will be provided by messages
18 printed on the bill, bill inserts, or separate letters from the Company to its
19 customers. In any case, notice would be provided prior to implementing
20 the change in the factors and charges related to the PSA.

21 **VIII. RESIDENTIAL RATE SCHEDULES**

22 **Q. WOULD YOU PLEASE GIVE A GENERAL DESCRIPTION OF THE**
23 **EXISTING RESIDENTIAL RETAIL RATE SCHEDULES?**

24 A. Currently, APS has seven Residential rate schedules. Two of the rates are for
25 special programs that APS actively supports and does not wish to change in any
26 way. Rate E-3 provides discounts for qualifying low-income customers. Rate E-4

1 provides a discounted rate to customers who must use electricity for medical care
2 equipment. We currently have three non time-of-use ("TOU") differentiated rates
3 (E-10, E-12, and EC-1). Rates E-10 and EC-1 were frozen by the Commission in
4 previous rate actions and have not been available to new customers for over 10
5 years. We also have two generally available TOU rates. Rate ET-1 is a time
6 differentiated energy rate, while Rate ECT-1R is time differentiated and also
7 includes a metered Demand charge.

8
9 **Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED RESIDENTIAL
RETAIL RATE SCHEDULES?**

10 A. As I noted earlier, we are unbundling the Standard Offer rates to comply with the
11 Competition Rules. Therefore, Rates E-12, ET-1, and ECT-1R will have discrete
12 charges for each of the Revenue Cycle Services, a Generation charge, a
13 Transmission charge, a Distribution charge, a Systems Benefits Charge, and the
14 various surcharges I discuss in my testimony.

15
16 **Q. WHAT ARE YOUR INTENTIONS FOR FROZEN RATE EC-1 AND ITS
CUSTOMERS?**

17 A. It is proposed that the frozen Rate EC-1 be eliminated. It is no longer available to
18 new customers and produces a low rate of return that can be considered a burden
19 to APS customers taking service on other rates. Rate EC-1 customers would be
20 transferred to Rate ECT-1R unless they choose an alternative rate. Rate ECT-1R
21 has been selected as the default rate as both rates have Demand components and
22 many customers currently on Rate EC-1 are managing their demand through load
23 controllers. These customers are aware of demand-based rates and the potential
24 for saving money by actively managing their peak load. Rate ECT-1R also has a
25 metered demand basis with the addition of a TOU element. Therefore, we believe
26

1 that the transition from Rate EC-1 to Rate ECT-1R would provide the best
2 continuity for the Rate EC-1 customers.

3
4 **Q. WHAT ARE YOUR INTENTIONS FOR FROZEN RATE E-10 AND ITS CUSTOMERS?**

5 A. It is proposed that frozen Rate E-10 be eliminated for the same basic reasons as
6 stated above for Rate EC-1. However, for customers on Rate E-10, I am
7 proposing a one-year phase-out period during which time APS would provide the
8 E-10 customers with information on alternative rate options. Customers will, of
9 course, be free to select any other Residential rate on which to take service. If a
10 Rate E-10 customer does not select another rate option during the phase-out
11 period, the default rate would be Rate E-12, since neither of those rates have time
12 differentiated pricing or a Demand charge. I am also requesting that the current
13 Rate E-10 be increased by 1.25 times the overall requested increase in this
14 proceeding. This increase would be effective during the one-year phase-out
15 period.

16
17 **Q. ARE YOU PROPOSING CHANGES TO RATE ET-1?**

18 A. Yes. In addition to unbundling the rate and increasing the charges to better
19 recover costs, we are adding some features not currently found in the existing
20 version of Rate ET-1. The first change is eliminating the TOU time periods
21 during the winter season. In effect, all hours during the winter can be thought of
22 as off-peak. When we examined hourly cost curves for the winter months, we
23 found that the time period differentials were relatively small. Therefore, an on-
24 peak price signal is not warranted. It should be noted that due to this winter
25 change, most federal and state holidays will no longer have time-differentiated
26 prices.

1 The second change proposed for Rate ET-1 is in response to research conducted
2 by APS Customer Service that indicated customers would prefer some additional
3 flexibility in the TOU rates. To accommodate that desire, we are proposing an
4 experiment in which APS would offer customers optional time periods. The
5 standard on-peak time period will continue to be 9AM to 9PM. Optional time
6 periods are to be 7AM to 7PM and 8AM to 8PM. We propose that these optional
7 time periods be initially limited to no more than 10,000 customers. In addition,
8 the number of customers switching will be limited each year based on staff and
9 meter availability.

10
11 **Q. WOULD YOU EXPLAIN WHY YOU HAVE PLACED RESTRICTIONS**
ON PARTICIPATION IN THIS EXPERIMENT?

12 A. The experiment will require individually reprogramming each participating
13 customer's meter. That will take time for APS personnel to accomplish and time
14 away from other tasks such as installing new meters to meet customer growth,
15 meter maintenance and replacement, etc.

16
17 Second, there should certainly be some revenue loss due to the fact that customers
18 will pick the TOU period that minimizes their on-peak consumption. Although I
19 cannot presently estimate this revenue attrition, it could be significant and it is not
20 accounted for in our rate filing. Thus, I would hope to be able to get better
21 information on the impact of this program on the Company and on other non-
22 participating APS customers before we make it available to all comers.

23 Lastly, to the extent that current non-TOU customers would find the proposed
24 "pick-a-period" TOU option attractive, it will require that we install TOU meters.
25 By limiting the program to 10,000 customers while in the experimental stage,
26

meter purchases and inventories can be better regulated.

Q. WOULD YOU DESCRIBE RATE ECT-1R, AS PROPOSED BY APS?

A. Yes, in addition to unbundling the rate and increasing the charges to better recover costs, Rate ECT-1R will continue to include time differentiated Energy charges and Demand charges in the Generation component. Currently, the on-peak time periods found in Rate ECT-1R are the same as found in Rate ET-1. Therefore, we propose the same TOU options be offered to Rate ECT-1R customers as will be offered to Rate ET-1 customers. Rate ECT-1R will also have no TOU differentiated energy component in the winter. It is intended that the 10,000 customer limit discussed with regard to the experimental "pick-a period" option be a total for both Rates ET-1 and ECT-1R taken together.

Q. ARE YOU PROPOSING CHANGES FOR RATE E-12?

A. Yes. In addition to increasing the rate level to bring it more in line with costs, the proposed rate has been simplified by eliminating one of the existing summer energy blocks.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED RESIDENTIAL RATE CHANGES?

A. We are proposing the following:

- All rates have been reformatted and include adjustment clause charges and surcharges.
- Rates E-12, ET-1, and ECT-1R will be unbundled.
- Each Residential rate will be designed to improve cost tracking.
- Rate EC-1 will be eliminated.
- Rate E-10 will be eliminated, phased out over one year, and increased by 1.25 times the overall increase requested in this proceeding.

- Rate E-12 will be redesigned and further simplified.
- Time period options will be made available to customers on Rates ET-1 and ECT-1R on an experimental and limited basis.
- TOU periods will be eliminated during the winter season.
- The low income and medical equipment rates, Rates E-3 and E-4 respectively, will remain unchanged.

IX. GENERAL SERVICE RATE SCHEDULES

Q. WOULD YOU PLEASE DESCRIBE APS' GENERAL SERVICE RATE SCHEDULES?

A. APS has eleven General Service rate schedules. These are basically used for serving our commercial and industrial loads. There are five TOU schedules, one schedule for unmetered service, one schedule for athletic stadiums and arenas, a seasonal schedule, and one schedule for partial requirements service. There are two demand based, non-TOU differentiated schedules. Approximately 95% of our General Service customers are served on Rate E-32. Rate E-34 and TOU Rate E-35 are available for customers whose loads exceed three megawatts.

Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED CHANGES IN THE GENERAL SERVICE SCHEDULES?

A. We propose to eliminate some frozen rate schedules, consolidate the TOU rates for customers under three megawatts, improve cost tracking and recovery, adjust rates with seasonal pricing differentials so that their summer and winter months correspond to those of our Residential rates, and unbundle the rate components.

Q. WOULD YOU PLEASE DESCRIBE THE PROPOSED RATE E-32?

A. In addition to unbundling charges and improving cost recovery, we propose to modify the format of Rate E-32. The current schedule is complex and includes

1 several billing blocks that are based on energy charges or load factor based
2 charges. We propose to simplify the structure, and make it more understandable
3 to our customers. The proposed schedule consists of two sections. The first
4 section is designed for customers whose loads are 20 kW or less. Customers will
5 be billed based on Energy charges without an explicit Demand charge. The
6 second section is designed for customers whose loads are greater than 20 kW but
7 less than 3,000 kW. Customers served under this section will be billed on the
8 basis of metered Demand and Energy. The Demand and Energy components each
9 have two billing blocks. The Demand charge has an initial rate block that ends at
10 500 kW. The Energy component has an initial block, which ends at 200 kWh/kW
11 or a 27 percent load factor. In addition, discounts will now be available for
12 customers taking service at Primary or Transmission voltage levels.

13 **Q. WHY WERE BILLING BLOCKS INCLUDED IN THE PROPOSED RATE**
14 **DESIGN?**

15 **A.** The blocks were needed to reduce the effect on individual customers as we move
16 from our existing Rate E-32 rate design to the more simplified design. In addition,
17 the 20 kW point corresponds to the load level at which metering requirements
18 change per the Competition Rules. Competitive customers with loads of greater
19 than 20 kW are required to have interval data recorder meters, while the loads for
20 customers of 20 kW or less can be load profiled, and therefore will not require
21 such metering.

22 **Q. HAVE YOU MODIFIED RATE E-32R?**

23 **A.** Yes. Rate E-32R provides for partial requirements customers basically taking
24 service under Rate E-32. The only changes proposed are to reflect the Demand
25
26

1 component modifications proposed for Rate E-32. For customers under 20 kW, a
2 contract demand will be established, as a measured demand may not be available.

3
4 **Q. WOULD YOU PLEASE DESCRIBE THE CHANGES PROPOSED IN THE
TOU RATE SCHEDULES FOR GENERAL SERVICE CUSTOMERS
UNDER 3 MW?**

5 A. As noted earlier in my testimony, we currently have a series of General Service
6 TOU rates. Customer participation on Rates E-21, E-22, E-23, and E-24 is capped
7 at a certain number of customers since these rates are experimental in nature. We
8 have proposed that these experimental rates now be eliminated, and replaced with
9 a new rate. Rate E-32TOU has been developed which will not be capped and will
10 parallel and follow the same concepts as the proposed non-TOU Rate E-32. There
11 is one section for customers 20 kW or less and one for customers over 20 kW.

12
13 **Q. WOULD YOU PLEASE SUMMARIZE THE PROPOSED CHANGES TO
THE GENERAL SERVICE SCHEDULES?**

14 A. Yes, the changes are as follows:

- 15 • All rates have been reformatted and include adjustment clause charges and
16 surcharges.
- 17 • Rates with seasonal pricing differentials have been modified so that their
18 summer and winter months correspond to those of our Residential rates.
- 19 • TOU Rates E-21, E-22, E-23, and E-24 will be eliminated and customers
20 transferred to E-32 TOU.
- 21 • Rate E-30 for Unmetered Service will be increased to better reflect costs
22 and the rate will be unbundled.
- 23 • Rate E-32 will be redesigned so that it will be unbundled and the rate
24 design simplified. In addition, discounts will be available for customers
25 who take service at Primary or Transmission voltage levels. The E-32R
26

1 rider has been modified to reflect the proposed change in Rate E-32.

- 2 • Rates E-34 and E-35 will be unbundled and the rates adjusted to allow for
3 discounts for service taken at Primary and Transmission voltage levels, and
4 to reflect the overall rate increase proposed in this rate case filing.
5 • Rate E-53 for service to Athletic Fields and Rate E-54 for Seasonal Service
6 are used in conjunction with other applicable General Service rates and no
7 stand alone changes to these rates are proposed.

8
9 X. CLASSIFIED SERVICE RATE SCHEDULES

10 Q. **WOULD YOU PLEASE DESCRIBE WHAT IS MEANT BY "CLASSIFIED SERVICE?"**

11 A. Classified Service provides for service to specific types of loads for which specific
12 rate schedules are available. Examples of Classified Service include service to
13 irrigation pumps and street lights.

14
15 Q. **WOULD YOU PLEASE PROVIDE A GENERAL DESCRIPTION OF THE PROPOSED CHANGES TO THE CLASSIFIED SERVICE SCHEDULE?**

16 A. Classified Service schedules tend to provide APS the lowest returns of all the rates
17 in our electric tariff. For example, irrigation pumps generally operate at low load
18 factors and during the summer months when the APS system peaks.
19 Consequently, the Irrigation rates are not at a level that provide APS with what I
20 would consider to be a reasonable rate of return. As I stated earlier in my
21 testimony, we have proposed that the rate increase for each major customer class
22 be limited to the overall average percentage increase that has been requested by
23 APS. This limitation simply does not allow for a meaningful unbundling of rate
24 schedules that vary greatly from following cost-of-service in their level or design.
25 Therefore, we have not proposed that all Classified Service rates be unbundled. In
26

1 addition, rates with seasonal pricing differentials have been modified so that their
2 summer and winter months correspond to those of our Residential rates.

3
4 **Q. WILL LIMITED UNBUNDLING PRESENT A BARRIER TO DIRECT ACCESS?**

5 A. No. Customers who are currently served under a Classified Service rate schedule,
6 such as Irrigation, can become a Direct Access customer by transferring to an
7 applicable General Service schedule and obtaining Distribution services through
8 the unbundled portion of the General Service rate.

9
10 **Q. WOULD YOU PLEASE DESCRIBE THE SPECIFIC CHANGES PROPOSED FOR THE IRRIGATION SCHEDULES?**

11 A. We currently have two basic Irrigation rates. Rate E-38 and its TOU companion
12 E-38-8T have less than 160 customers. Rate E-221 and its TOU companion E-
13 221-8T have approximately 1,400 Irrigation customers. We propose eliminating
14 Rates E-38 and E-38-8T and transferring those customers to Rates E-221 or E-
15 221-8T. Charges on Rate E-221 will be increased to meet our overall rate increase
16 request along with some rate design modifications to make the rate more cost
17 tracking. It is expected that some Irrigation class customers currently taking
18 service on General Service Rate E-32 will transfer to Rate E-221 to take advantage
19 of the effect the proposed design changes have on their particular loads.

20
21 **Q. ARE YOU PROPOSING CHANGES TO THE STREET LIGHTING AND DUSK TO DAWN LIGHTING SCHEDULES?**

22 A. Yes, in addition to improved cost tracking, we have reformatted Rate E-47 (Dusk
23 to Dawn) and Rate E-58 (Street Lighting). Because customers on these rates often
24 request different combinations of poles, arms, and fixtures, we have developed and
25 proposed a menu format for these rates. Subject to certain physical/construction
26 limitations, customers will be able to select the lighting system that best fits their

1 needs. The menu system will also make it easier to add new poles or fixtures to
2 the rate schedules, as they become available.

3 **Q. HOW DID YOU RESTRUCTURE THE CHARGES WITHIN RATES E-47**
4 **AND E-58?**

5 A. APS performed an extensive analysis of the costs of installing and maintaining
6 each type of lighting equipment that we offer. This analysis resulted in
7 recommended changes to the relationship between charges in the menu. The
8 relative price of some fixtures increased while the relative price of other fixtures
9 declined.

10 **Q. DOES APS PROVIDE STREET LIGHTING SERVICE ON RATES OTHER**
11 **THAN E-58?**

12 A. Yes, Rate E-59 is used to provide energy service for government-owned street
13 lighting systems. Under Rate E-59, APS has no responsibility for operations,
14 maintenance, or replacement of street light poles or fixtures. There is also a series
15 of "Share the Light" schedules for Street Lighting services in Litchfield Park, Ajo,
16 Camp Verde, and other areas. The charges for these special schedules are found in
17 Rate E-58.

18 **Q. WHAT ARE THE PROPOSED CHANGES FOR THESE STREET**
19 **LIGHTING RATES?**

20 A. APS proposes to increase the overall charges under each of these rates at
21 approximately the same level as our overall requested increase.

22 **Q. ARE THERE ANY OTHER LIGHTING RELATED RATE SCHEDULES**
23 **IN THE TARIFF?**

24 A. Rate E-67 is used to provide energy service to the City of Phoenix for various non-
25 Street Lighting systems. It is based on an old contract rate that has long expired.
26 Because the level of this rate and its return is so substandard, I propose that it be

1 increased by twice the average percent increase that APS is requesting in this rate
2 case. This requested increase will still not bring the rate up to the average rate of
3 return paid by our other retail customers.

4
5 **Q. WOULD YOU PLEASE DESCRIBE ANY OTHER PROPOSED CHANGES**
6 **FOR CLASSIFIED SERVICE CUSTOMERS?**

7 A. Rate E-20 is used to provide TOU service to houses of worship. The pricing under
8 this rate schedule is the same as the pricing under Rate E-21, which has been
9 frozen since 1996, and has been eliminated in our rate proposal. We propose that
10 Rate E-20 be frozen and therefore not available to new customers. New customers
11 would take service on Rate E-32TOU or another General Service rate of their
12 choice. Charges for customers who remain on Rate E-20 will be increased by one
13 and one half times the overall requested increase in this proceeding.

14 We propose that charges under Rate E-40 for service to Agricultural Wind
15 Machines and charges under frozen Rate E-51 for service to certain cogenerators
16 and small power producers be increased by the same overall percentage as is being
17 requested in this proceeding.

18 Partial Requirements Service Rates E-52 and E-55 currently have no customers
19 being served on them and no increase is proposed at this time.

20 In addition, and as with our other rates, the Classified Service rate schedules will
21 include provisions for the requested adjustment clause charges and surcharges.
22
23
24
25
26

1 XI. DIRECT ACCESS RATES

2 Q. **WHAT WILL HAPPEN TO APS' EXISTING DIRECT ACCESS RATES?**

3 A. Because we have functionally unbundled our applicable Standard Offer rates, the
4 existing separate special Direct Access rates will no longer be necessary and,
5 therefore, have been eliminated in our proposal. Customers seeking Direct Access
6 service would purchase the required non-competitive services from APS as listed
7 under the appropriate unbundled Standard Offer rate schedule. One or more ESPs
8 would provide the needed competitive services. Currently, APS has no customers
9 taking Direct Access service.

10

11 XII. "H" SCHEDULES

12 Q. **WOULD YOU DESCRIBE THE "H" SCHEDULES BEING SPONSORED BY YOU?**

13 A. The "H" Schedules are a series of summaries that present an analysis of the
14 impacts of the proposed rates.

15

16 Q. **WOULD YOU PLEASE DESCRIBE SCHEDULE H-1?**

17 A. Schedule H-1 provides a summary of the revenue impact on each major customer
18 classification, e.g. Residential, General Service, Irrigation, etc. This schedule
19 compares the revenue generated under the proposed rates with the revenue
20 generated under present rates.

21

22 To develop the data found in the column entitled "Present Rates," we began with
23 actual revenue from the test year, but then made a series of normalization
24 adjustments to that data. The adjustments were made to reflect normal weather,
25 the year-end number of customers, the rate decreases that were effective in July of
26 2002 and 2003, and the removal of revenue associated with Franchise Fees

1 included in current rate levels. The purpose of these adjustments was to enable us
2 to compare existing and proposed rates on an "apples to apples" basis. For
3 example, our current existing rates are based on costs that include approximately
4 \$29 million in Franchise Fee costs. We have proposed that, in the future,
5 Franchise Fees will be treated like any other surcharged tax. If we did not remove
6 the Franchise Fee costs from current rates levels, comparisons to the proposed
7 rates would be less meaningful and very confusing.

8
9 **Q. WOULD YOU DESCRIBE THE INFORMATION FOUND IN SCHEDULE H-2?**

10 A. Schedule H-2 presents the information found in Schedule H-1 in a more detailed
11 format. The comparisons of current and proposed revenue are shown by rate
12 schedule whereas Schedule H-1 data is presented on a class basis. Schedule H-1 is
13 actually a summary of the data found in Schedule H-2.

14
15 **Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-3?**

16 A. Schedule H-3 presents comparisons of the specifics of each rate schedule. These
17 specifics include details such as the Basic Service Charge, billing blocks, Energy
18 charges, and Demand charges. Although our proposed rates have been
19 functionally unbundled, the information shown on Schedule H-3 is presented on a
20 bundled basis to allow for easier comparisons to existing rate schedules.
21 Additionally, in the proposed rates section, we have included a column that shows
22 the proposed rates with the addition of a Franchise Fee element. The Franchise
23 Fee element is based on the average Franchise Fee currently recovered in base
24 rates. As I noted earlier in my testimony, we have included this information so
25 that rate comparisons can be made on a common basis, with the knowledge that
26

1 the Franchise Fee actually passed through to an individual customer will vary by
2 municipality.

3
4 **Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-4?**

5 A. Schedule H-4 presents a typical bill comparison for our major rate schedules under
6 existing and proposed rates. Bill comparisons are presented for varying levels of
7 consumption and for seasons, when applicable. Schedule H-4 also includes
8 additional columns of information so that complete comparisons can be made
9 between existing and proposed rates. The additional columns show the Franchise
10 Fees and the Competition Rules Compliance Charge ("CRCC"). These charges
11 are added to the revenues determined by the rates so that a more complete "bill"
12 can be computed. The "add-ons" of Sales Tax and Regulatory Assessment have
13 not been included in the bill comparisons.

14 **Q. WHAT IS THE CRCC?**

15 A. In May of 2002, APS filed an amended application with the ACC requesting
16 approval for a series of adjusters or surcharges including a PSA and the CRCC.
17 The adjuster/surcharge request filing was made in accordance with the terms of the
18 1999 Settlement Agreement. The CRCC was developed to enable APS to recover
19 the costs the Company incurred in order to comply with the Competition Rules.
20 These costs are not recovered in current rates. However, since customers will see
21 the CRCC charge on bills when APS' revised rates become effective, a column
22 has been included on Schedule H-4 that demonstrates the impact of the CRCC on
23 bills. The CRCC will be in effect for five years.

1 Q. WOULD YOU PLEASE DESCRIBE SCHEDULE H-5?

2 A. Schedule H-5 presents a series of bill frequency analyses for major rate schedules.
3 This information includes the number of bills and energy consumed based on
4 blocks of consumption levels. The data is presented for our Residential rate
5 schedules. Data is not presented for the General Service schedules because the bill
6 frequency data cannot be presented in a meaningful manner for customer classes
7 in which customers are billed on both metered demand and energy.
8

9 XIII. CONCLUSION

10 Q. WOULD YOU STATE YOUR GENERAL CONCLUSIONS AS TO
11 PRICING MATTERS IN THIS PROCEEDING?

12 A. The cost-of-service study has shown me that APS' current rates produce rates of
13 return that vary greatly from each other and from the overall average and required
14 rate of return. In addition, the rate designs stray greatly from the unit Demand,
15 Energy, and Customer costs of providing service to our customers. The rates
16 being proposed in this proceeding will meet APS' revenue requirement, better
17 track costs, and have been simplified for better customer understanding and
18 administration.

19 Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

20 A. Yes it does.
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Appendix A
Statement of Qualifications
Alan Propper

Alan Propper is Arizona Public Service Company's Director of Pricing. He is a veteran of the electric and gas utility industry with over 30 years of experience in utility company management and as an industry consultant. Mr. Propper holds the degrees of Mechanical Engineer from Stevens Institute of Technology and Master of Business Administration from San Francisco State University. The Arizona State Community College Certification Board has certified him as an Instructor of Engineering and Business Administration.

Mr. Propper's areas of expertise include pricing and rate design, embedded and marginal cost analyses, load research, load management programs, state and federal regulatory matters, contract negotiations between utilities concerning resale and wheeling services, contract negotiations between utilities and their major retail customers, and tariff administration. Mr. Propper has testified on numerous occasions on contract, pricing, and cost-of-service matters before many state and federal regulatory agencies.

Prior to rejoining APS after an eight year absence, Mr. Propper served as Regional Manager and Managing Executive Consultant for Resource Management International (now Navigant) and Principal Consultant and Director of Consulting Services for A&C Enercom. Prior to initially joining APS, Mr. Propper was employed as Supervisor of Rates for Consumers Power Company, Executive Consultant for Commonwealth Services, Forecast Engineer and Rate Engineer for Pacific Gas & Electric Company, and in Power Plant Operations for Public Service Electric & Gas Company.

1369170.1

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DEC. 31, 2002
(\$)

		GJ		
		ELECTRIC TOTAL (1)	ACC JURISDICTION (2)	ALL OTHER (3)
Line No.	Description			
SUMMARY OF RESULTS				
1	DEVELOPMENT OF RATE BASE			
2	ELECTRIC PLANT IN SERVICE	\$7,909,989,000	\$7,637,477,656	\$272,511,344
3	GENERAL & INTANGIBLE PLANT	\$576,885,334	\$565,827,594	\$11,057,740
4	LESS: RESERVE FOR DEPRECIATION	(\$3,542,546,796)	(\$3,405,508,821)	(\$137,037,975)
5	OTHER DEFERRED CREDITS	(\$173,561,000)	(\$172,549,446)	(\$1,011,554)
6	WORKING CASH	\$54,097,992	\$52,979,748	\$1,118,244
7	MATERIALS, SUPPLIES & PREPAYMENTS	\$121,614,469	\$119,442,953	\$2,171,516
8	ACCUM. DEFERRED TAXES	(\$1,296,415,000)	(\$1,272,578,862)	(\$23,836,138)
9	REGULATORY ASSETS	\$166,267,910	\$165,564,194	\$703,716
10	DECOMMISSIONING FUND	\$194,440,466	\$191,607,661	\$2,832,805
11	GAIN FROM DISP. OF PLANT	(\$59,484,000)	(\$59,380,841)	(\$103,159)
12	MISCELLANEOUS DEFERRED DEBITS	\$27,379,000	\$26,958,959	\$420,041
13	CUSTOMER ADVANCES	(\$45,512,876)	(\$45,512,876)	\$0
14	CUSTOMER DEPOSITS	(\$39,865,000)	(\$39,865,000)	\$0
15	PROFORMA ADJUSTMENTS	\$327,729,500	\$443,013,080	(\$115,283,580)
16	TOTAL RATE BASE	\$4,221,018,999	\$4,207,475,999	\$13,543,000
17				
18	DEVELOPMENT OF RETURN			
19	REVENUES FROM RATES	\$1,874,801,594	\$1,839,197,107	\$35,604,487
20	PROFORMA TO REVENUES FROM RATES	(\$47,613,375)	(\$47,613,375)	\$0
21	OTHER ELECTRIC REVENUE	\$150,987,521	\$148,562,410	\$2,425,111
22	TOTAL OPERATING REVENUES	\$1,978,175,740	\$1,940,146,142	\$38,029,598
23				
24	OPERATING EXPENSES			
25	OPERATION & MAINTENANCE	\$1,014,770,483	\$998,176,929	\$16,593,554
26	ADMINISTRATIVE & GENERAL	\$109,788,347	\$108,572,720	\$1,215,627
27	DEPRECIATION & AMORT EXPENSE	\$273,216,517	\$266,778,129	\$6,438,388
28	AMORTIZATION ON GAIN	(\$4,708,735)	(\$4,698,862)	(\$9,873)
29	REGULATORY ASSETS	\$114,979,666	\$114,979,666	\$0
30	PROFORMA ADJUSTMENTS	(\$4,875,035)	(\$13,023,229)	\$8,148,194
31	TAXES OTHER THAN INCOME	\$123,391,838	\$119,346,144	\$4,045,694
32	INCOME TAX	\$86,607,563	\$86,144,085	\$463,478
33	TOTAL OPERATING EXPENSES	\$1,713,170,644	\$1,676,275,581	\$36,895,063
34				
35	OPERATING INCOME	\$265,005,096	\$263,870,561	\$1,134,535
36				
37	RETURN	\$265,005,096	\$263,870,561	\$1,134,535
38				
39	RATE OF RETURN (PRESENT)	6.28%	6.27%	8.38%
40				
41	INDEX RATE OF RETURN (PRESENT)	1.00	1.00	1.33

		GE-1						
Line No.	Description	TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	IRRIGATION (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)	
SUMMARY OF RESULTS								
DEVELOPMENT OF RATE BASE								
1	ELECTRIC PLANT IN SERVICE	\$7,637,477,656	\$4,232,372,444	\$3,291,758,562	\$12,488,353	\$70,515,364	\$30,342,932	
2	GENERAL & INTANGIBLE PLANT	\$565,827,594	\$342,186,241	\$214,880,479	\$840,639	\$5,179,407	\$2,740,828	
3	LESS: RESERVE FOR DEPRECIATION	(\$3,405,508,821)	(\$1,852,081,097)	(\$1,514,197,687)	\$5,423,455)	(\$23,515,621)	(\$10,290,960)	
4	OTHER DEFERRED CREDITS	(\$172,549,446)	(\$93,339,740)	(\$78,240,066)	(\$272,530)	(\$457,389)	(\$239,721)	
5	WORKING CASH	\$52,979,748	\$29,244,091	\$22,993,439	\$80,589	\$452,725	\$208,904	
6	MATERIALS, SUPPLIES & PREPAYMENTS	\$119,442,953	\$62,245,085	\$55,895,336	\$188,712	\$782,591	\$331,228	
7	ACCUM. DEFERRED TAXES	(\$1,272,578,862)	(\$689,516,808)	(\$569,702,479)	(\$2,084,756)	(\$7,890,379)	(\$3,384,439)	
8	REGULATORY ASSETS	\$165,564,194	\$82,742,988	\$82,279,646	\$256,569	\$207,897	\$77,094	
9	DECOMMISSIONING FUND	\$191,607,661	\$86,668,985	\$103,484,099	\$260,707	\$870,910	\$322,960	
10	GAIN FROM DISP. OF PLANT	(\$59,380,841)	(\$30,751,661)	(\$28,532,875)	(\$96,305)	\$0	\$0	
11	MISCELLANEOUS DEFERRED DEBITS	\$26,958,959	\$16,306,046	\$10,235,120	\$40,124	\$246,948	\$130,722	
12	CUSTOMER ADVANCES	(\$45,512,876)	(\$29,881,809)	(\$12,797,831)	(\$2,373,090)	(\$460,146)	\$0	
13	CUSTOMER DEPOSITS	(\$39,865,000)	(\$18,337,900)	(\$21,081,530)	(\$52,324)	(\$267,833)	(\$125,412)	
14	PROFORMA ADJUSTMENTS	\$443,013,080	\$229,255,123	\$213,024,093	\$717,815	\$11,708	\$4,342	
15	TOTAL RATE BASE	\$4,207,475,999	\$2,367,111,987	\$1,769,998,307	\$4,571,046	\$45,676,181	\$20,118,478	
16								
17								
DEVELOPMENT OF RETURN								
18	REVENUES FROM RATES	\$1,839,197,107	\$911,780,435	\$908,197,108	\$2,257,000	\$11,567,156	\$5,395,408	
19	PROFORMA TO REVENUES FROM RATES	(\$47,613,375)	(\$21,882,852)	(\$24,601,762)	(\$157,808)	(\$773,504)	(\$197,449)	
20	OTHER ELECTRIC REVENUE	\$148,562,410	\$71,186,642	\$74,249,338	\$214,786	\$2,582,662	\$328,981	
21	TOTAL OPERATING REVENUES	\$1,940,146,142	\$961,084,225	\$957,844,684	\$2,313,978	\$13,376,314	\$5,526,940	
22								
23								
OPERATING EXPENSES								
24	OPERATION & MAINTENANCE	\$998,176,929	\$504,207,958	\$482,891,907	\$1,450,345	\$7,185,387	\$2,441,332	
25	ADMINISTRATIVE & GENERAL	\$108,572,720	\$65,579,950	\$40,778,896	\$167,469	\$1,382,051	\$664,353	
26	DEPRECIATION & AMORT EXPENSE	\$266,778,129	\$151,202,510	\$111,026,243	\$431,240	\$2,856,588	\$1,261,548	
27	AMORTIZATION ON GAIN	(\$4,698,862)	(\$2,424,816)	(\$2,265,642)	(\$7,586)	(\$596)	(\$221)	
28	REGULATORY ASSETS	\$114,979,866	\$59,544,722	\$55,248,467	\$186,476	\$0	\$0	
29	PROFORMA ADJUSTMENTS	(\$13,023,229)	(\$6,902,815)	(\$5,682,301)	(\$62,178)	(\$324,438)	(\$51,498)	
30	TAXES OTHER THAN INCOME	\$119,346,144	\$68,525,934	\$48,688,043	\$193,761	\$1,339,525	\$598,881	
31	INCOME TAX	\$86,144,085	\$18,615,690	\$67,805,516	(\$74,606)	(\$195,292)	(\$7,223)	
32	TOTAL OPERATING EXPENSES	\$1,676,275,581	\$858,349,133	\$798,491,130	\$2,284,920	\$12,243,225	\$4,907,174	
33								
34								
35	OPERATING INCOME	\$263,870,561	\$102,735,092	\$159,353,555	\$29,058	\$1,133,090	\$619,767	
36								
37	RETURN	\$263,870,561	\$102,735,092	\$159,353,555	\$29,058	\$1,133,090	\$619,767	
38								
39	RATE OF RETURN (PRESENT)	6.27%	4.34%	9.00%	0.64%	2.48%	3.08%	
40								
41	INDEX RATE OF RETURN (PRESENT)	1.00	0.69	1.43	0.10	0.40	0.49	

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DEC. 31, 2002
(8)

		GE-2					→	
Line No.	Description	TOTAL	SMALL	MEDIUM	LARGE	EXTRA-LARGE		
		GENERAL SVC (10)	GEN. SERVICE (11)	GEN. SERVICE (12)	GEN. SERVICE (13)	GEN. SERVICE (14)		
SUMMARY OF RESULTS								
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	\$3,291,758,562	\$1,206,095,683	\$1,336,430,292	\$357,971,573	\$391,261,013		
3	GENERAL & INTANGIBLE PLANT	\$214,880,479	\$85,681,122	\$78,785,796	\$22,551,051	\$27,862,510		
4	LESS: RESERVE FOR DEPRECIATION	(\$1,514,197,687)	(\$538,474,987)	(\$609,735,998)	(\$189,515,642)	(\$196,471,061)		
5	OTHER DEFERRED CREDITS	(\$78,240,066)	(\$27,450,487)	(\$31,003,705)	(\$8,928,400)	(\$10,857,474)		
6	WORKING CASH	\$22,993,439	\$8,168,419	\$8,985,687	\$2,601,327	\$3,238,006		
7	MATERIALS, SUPPLIES & PREPAYMENTS	\$55,895,336	\$18,691,977	\$22,419,236	\$6,552,777	\$8,231,346		
8	ACCUM. DEFERRED TAXES	(\$569,702,479)	(\$202,880,381)	(\$231,433,493)	(\$63,513,382)	(\$71,875,223)		
9	REGULATORY ASSETS	\$82,279,646	\$26,402,002	\$33,114,365	\$9,944,051	\$12,819,228		
10	DECOMMISSIONING FUND	\$103,484,099	\$29,107,580	\$40,867,606	\$13,561,603	\$19,947,311		
11	GAIN FROM DISP. OF PLANT	\$28,532,875	(\$9,640,509)	(\$11,575,733)	(\$3,323,605)	(\$3,993,028)		
12	MISCELLANEOUS DEFERRED DEBITS	\$10,235,120	\$4,081,828	\$3,751,032	\$1,074,160	\$1,328,100		
13	CUSTOMER ADVANCES	(\$12,797,830)	(\$4,729,974)	(\$5,077,344)	(\$1,212,923)	(\$1,777,590)		
14	CUSTOMER DEPOSITS	\$21,081,530	(\$7,814,202)	(\$8,349,369)	(\$1,993,379)	(\$2,924,582)		
15	PROFORMA ADJUSTMENTS	\$213,024,093	\$71,896,508	\$86,408,468	\$24,834,029	\$29,885,088		
16	TOTAL RATE BASE	\$1,769,998,307	\$659,134,580	\$713,586,840	\$190,603,241	\$206,673,646		
17								
18	DEVELOPMENT OF RETURN							
19	REVENUES FROM RATES	\$908,197,108	\$335,662,237	\$360,313,341	\$86,074,979	\$126,146,551		
20	PROFORMA TO REVENUES FROM RATES	(\$24,601,762)	(\$7,796,931)	(\$13,741,145)	(\$3,835,236)	\$771,550		
21	OTHER ELECTRIC REVENUE	\$74,249,338	\$22,605,331	\$29,539,363	\$9,282,155	\$12,822,490		
22	TOTAL OPERATING REVENUES	\$957,844,684	\$350,470,637	\$376,111,559	\$91,521,898	\$139,740,591		
23								
24	OPERATING EXPENSES							
25	OPERATION & MAINTENANCE	\$482,891,907	\$151,015,727	\$187,851,693	\$59,804,779	\$84,219,709		
26	ADMINISTRATIVE & GENERAL	\$40,778,896	\$16,459,677	\$15,411,629	\$4,167,768	\$4,739,821		
27	DEPRECIATION & AMORT EXPENSE	\$111,026,243	\$41,705,361	\$44,549,096	\$11,864,335	\$12,907,452		
28	AMORTIZATION ON GAIN	(\$2,265,642)	(\$761,494)	(\$918,404)	(\$264,941)	(\$320,804)		
29	REGULATORY ASSETS	\$55,248,467	\$18,667,006	\$22,414,197	\$6,435,527	\$7,731,736		
30	PROFORMA ADJUSTMENTS	(\$5,682,301)	\$1,063,327	(\$2,767,102)	(\$2,037,870)	(\$1,940,656)		
31	TAXES OTHER THAN INCOME	\$48,688,043	\$18,595,321	\$19,428,372	\$5,135,385	\$5,528,965		
32	INCOME TAX	\$67,805,516	\$32,807,944	\$26,767,990	\$173,964	\$8,055,619		
33	TOTAL OPERATING EXPENSES	\$798,491,130	\$279,552,869	\$312,737,471	\$85,278,948	\$120,921,841		
34								
35	OPERATING INCOME	\$159,353,555	\$70,917,768	\$63,374,088	\$6,242,949	\$18,818,749		
36								
37	RETURN	\$159,353,555	\$70,917,768	\$63,374,088	\$6,242,949	\$18,818,749		
38								
39	RATE OF RETURN (PRESENT)	9.00%	10.76%	8.88%	3.28%	9.11%		
40								
41	INDEX RATE OF RETURN (PRESENT)	1.43	1.71	1.41	0.52	1.45		

		GE-3												
Line No.	Description	TOTAL RESIDENTIAL		RESIDENTIAL		RESIDENTIAL		RESIDENTIAL		RESIDENTIAL		RESIDENTIAL		
		(15)	(16)	(17)	(18)	(20)	(21)	(15)	(16)	(17)	(18)	(20)	(21)	
SUMMARY OF RESULTS														
DEVELOPMENT OF RATE BASE														
1	ELECTRIC PLANT IN SERVICE	\$4,232,372,444	\$384,083,652	\$1,301,283,148	\$206,561,469	\$1,937,185,658		\$403,258,518						
2	GENERAL & INTANGIBLE PLANT	\$342,186,241	\$32,811,770	\$119,614,373	\$15,343,639	\$145,648,731		\$28,767,728						
3	LESS: RESERVE FOR DEPRECIATION	(\$1,852,081,097)	(\$167,811,378)	(\$568,016,302)	(\$92,392,271)	(\$845,927,724)		(\$177,993,429)						
4	OTHER DEFERRED CREDITS	(\$93,339,740)	(\$8,458,699)	(\$28,823,032)	(\$4,748,685)	(\$42,483,627)		(\$8,825,697)						
5	WORKING CASH	\$29,244,091	\$2,715,983	\$9,448,160	\$1,417,157	\$12,910,392		\$2,752,398						
6	MATERIALS, SUPPLIES & PREPAYMENTS	\$62,245,085	\$5,645,569	\$18,971,646	\$3,190,088	\$28,194,883		\$6,242,900						
7	ACCUM. DEFERRED TAXES	(\$689,516,808)	(\$61,978,706)	(\$207,928,101)	(\$34,700,768)	(\$318,332,612)		(\$66,576,621)						
8	REGULATORY ASSETS	\$82,742,988	\$7,352,549	\$24,185,230	\$4,494,768	\$38,195,531		\$8,514,910						
9	DECOMMISSIONING FUND	\$86,668,985	\$7,884,417	\$25,935,286	\$4,908,048	\$37,999,671		\$9,941,563						
10	GAIN FROM DISP. OF PLANT	(\$30,751,661)	(\$2,710,947)	(\$8,917,233)	(\$1,646,832)	(\$14,433,034)		(\$3,043,616)						
11	MISCELLANEOUS DEFERRED DEBITS	\$16,306,046	\$1,563,665	\$5,701,497	\$731,108	\$6,939,454		\$1,370,322						
12	CUSTOMER ADVANCES	(\$29,881,809)	(\$2,811,117)	(\$10,069,381)	(\$1,514,183)	(\$12,589,088)		(\$2,896,088)						
13	CUSTOMER DEPOSITS	(\$18,337,900)	(\$1,725,129)	(\$6,179,388)	(\$929,225)	(\$7,725,656)		(\$1,778,502)						
14	PROFORMA ADJUSTMENTS	\$229,255,123	\$20,213,520	\$66,489,202	\$12,280,799	\$107,562,969		\$22,708,633						
15	TOTAL RATE BASE	\$2,367,111,987	\$216,775,149	\$741,695,106	\$112,995,111	\$1,073,145,595		\$222,501,026						
16														
17	DEVELOPMENT OF RETURN													
18	REVENUES FROM RATES	\$911,780,435	\$85,775,314	\$307,245,930	\$46,202,107	\$384,128,045		\$88,429,039						
19	PROFORMA TO REVENUES FROM RATES	(\$21,882,852)	(\$6,853,175)	(\$5,812,496)	(\$3,449,426)	(\$3,015,166)		(\$2,752,589)						
20	OTHER ELECTRIC REVENUE	\$71,186,642	\$6,468,618	\$21,508,908	\$3,833,679	\$31,726,327		\$7,649,111						
21	TOTAL OPERATING REVENUES	\$961,084,225	\$85,390,757	\$322,942,342	\$46,586,360	\$412,839,206		\$93,325,561						
22														
23	OPERATING EXPENSES													
24	OPERATION & MAINTENANCE	\$504,207,958	\$46,962,540	\$161,169,522	\$26,074,132	\$218,635,643		\$51,366,120						
25	ADMINISTRATIVE & GENERAL	\$65,579,950	\$6,246,711	\$22,502,502	\$2,913,077	\$28,271,323		\$5,646,338						
26	DEPRECIATION & AMORT EXPENSE	\$151,202,510	\$13,899,320	\$47,790,119	\$7,188,772	\$68,254,263		\$14,080,036						
27	AMORTIZATION ON GAIN	(\$2,424,816)	(\$213,929)	(\$703,687)	(\$130,038)	(\$1,136,235)		(\$240,927)						
28	REGULATORY ASSETS	\$59,544,722	\$5,249,231	\$17,266,519	\$3,188,776	\$27,946,816		\$5,893,381						
29	PROFORMA ADJUSTMENTS	(\$6,902,815)	(\$356,027)	\$573,752	(\$520,659)	(\$5,352,249)		(\$1,247,632)						
30	TAXES OTHER THAN INCOME	\$68,525,934	\$6,326,819	\$21,917,460	\$3,215,890	\$30,770,315		\$6,295,451						
31	INCOME TAX	\$18,615,690	\$1,193,138	\$11,522,065	\$439,781	\$4,661,039		\$1,799,667						
32	TOTAL OPERATING EXPENSES	\$858,349,133	\$78,297,802	\$282,038,252	\$42,369,732	\$372,050,914		\$83,692,434						
33														
34	OPERATING INCOME	\$102,735,092	\$7,092,955	\$40,904,090	\$4,216,629	\$40,788,292		\$9,733,127						
35														
36	RETURN	\$102,735,092	\$7,092,955	\$40,904,090	\$4,216,629	\$40,788,292		\$9,733,127						
37														
38	RATE OF RETURN (PRESENT)	4.34%	3.27%	5.51%	3.73%	3.80%		4.37%						
39														
40	INDEX RATE OF RETURN (PRESENT)	0.69	0.52	0.88	0.59	0.61		0.70						
41														

Testimony
of
David J.
Rumolo

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DIRECT TESTIMONY OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-___

June 27, 2003

Table of Contents

TABLE OF CONTENTS	i
I. INTRODUCTION	1
II. SUMMARY OF TESTIMONY	2
III. SCHEDULE 1 - GENERAL TERMS AND CONDITIONS	3
IV. SCHEDULE 3 - LINE EXTENSIONS	6
V. SCHEDULE 4 - TOTALIZING	12
VI. SCHEDULE 7 - METER PERFORMANCE MONITROING PLAN	13
VII. SCHEDULE 10 - TERMS AND CONDITIONS FOR DIRECT ACCESS	13
VIII. SCHEDULE 15 - SPECIALIZED METERING	13
STATEMENT OF QUALIFICATIONS	Appendix A
SCHEDULE # 1 (PROPOSED AND REDLINED)	Appendix B
SCHEDULE # 3 (PROPOSED AND REDLINED)	Appendix B
SCHEDULE # 4 (PROPOSED AND REDLINED)	Appendix B
SCHEDULE # 7 (PROPOSED AND REDLINED)	Appendix B
SCHEDULE # 10 (PROPOSED AND REDLINED)	Appendix B
SCHEDULE # 15 (PROPOSED AND REDLINED)	Appendix B

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

Q. WOULD YOU PLEASE DESCRIBE THE FUNCTIONS OF THE COMPANY'S STATE PRICING GROUP?

A. The State Pricing Group is part of the APS Pricing and Regulation Department. The Group is responsible for all retail pricing-related activities including rate development, service policy development, and development of material for filings with the Arizona Corporation Commission (“Commission”).

O. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the proposed changes to APS' service schedules that address policies pertaining to providing retail electric service to customers. These service schedules include both general terms and conditions of service and specific policies on topics such as line extensions, meter testing, direct access requirements, and specialized metering.

1 II. SUMMARY OF TESTIMONY

2 Q. **WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?**

3 A. My testimony addresses proposed changes to the APS service schedules on file
4 with the Commission. APS is proposing revisions to Schedule 1 that will impact
5 current revenue. All the other changes to the service schedules will have no
6 revenue impact. However, the Company is also proposing changes in Schedule
7 3 that may impact the contributions to capital that customers and developers
8 make when requesting new services that require line extensions.

9
10 Q. **WHY ARE YOU PROPOSING REVISIONS TO THE SERVICE SCHEDULES?**

11 A. Because APS is revising its retail rate schedules in this rate case, we determined
12 that this would also be an appropriate time to examine all of the aspects of our
13 retail tariff. Many of the service schedules have not been reviewed in years.
14 Thus, the Company examined them in the context of current electric utility
15 trends and practices and to allow the Company to charge cost-based fees for
16 special services to customers requiring the services. This ensures that the entire
17 customer base is not paying for costs caused only by a few customers

18
19 Q. **WHAT PROCESSES WERE USED TO REVIEW THE SERVICE SCHEDULES?**

20 A. We formed working groups comprised of employees who are involved in the
21 implementation and administration of the schedules. These are the "hands-on"
22 personnel who deal with the service schedules on a daily basis. They were asked
23 to review the schedules and propose appropriate changes.

1 **Q. IN GENERAL, WHAT IS THE NATURE OF THE PROPOSED**
2 **CHANGES?**

3 A. Many of the changes are simply editorial in nature. For example, some service
4 schedules had inconsistent or potentially confusing formatting. Thus, in some
5 service schedules, without defining either term, APS was referred to as
6 "Company" in some places and as "APS" in other places. We have reformatted
7 the schedules to address these inconsistencies. We also reviewed current charges
8 or instituted new charges to ensure that the service schedules adequately reflect
9 the costs for customer-requested activities. I will explain each of these charges
10 later in this testimony. Each service schedule for which APS is proposing
11 changes is attached to my testimony as Appendix B. In the set of service
12 schedules provided in Appendix B, the proposed changes from the current
13 schedules are shown in redline format.

14 **III. SCHEDULE 1 - GENERAL TERMS AND CONDITIONS**

15 **Q. PLEASE DESCRIBE THE PROPOSED CHANGES IN SCHEDULE 1**
16 **THAT IMPACT APS' REVENUE.**

17 A. Schedule 1 lists the terms and conditions for service. I will highlight some of
18 the more significant changes that are proposed. First, APS is proposing that the
19 Company be allowed to assess a "trip charge" to customers when appropriate.
20 For example, a trip charge would be assessed when a service technician travels
21 to a customer's premise to complete a customer-requested service, but is unable
22 to complete the service because of lack of meter access. Also, APS proposes to
23 increase the "after hours" charge to reflect current costs for meter reading,
24 installation or turn on service and is requesting the ability to charge the customer
25 an hourly rate for other after-hours or holiday work.
26

1 **Q. WHY ARE THESE CHANGES BEING REQUESTED?**

2 A. These changes are being proposed so that APS can better address cost causation
3 and charge customers appropriately. For example, if a service call is requested
4 for after-hours work to better accommodate a customer's specific request, it is
5 appropriate for that customer to bear the additional cost of that special service.
6 Otherwise, in the long run, all customers may pay for the costs of special service
7 requested by a few customers.

8 **Q. WILL ANY OF THE PROPOSED CHANGES IN SCHEDULE 1 RESULT**
9 **IN HIGHER CHARGES TO CUSTOMERS?**

10 A. Yes, some customers may see higher charges. However, any such higher
11 changes are limited to "optional" services and are entirely within a customer's
12 control. I have tabulated the old and new charges below:

DESCRIPTION (SCHEDULE 1 SECTION)	CURRENT CHARGE	PROPOSED CHARGE
Trip charge (2.2.1)	None	\$17.50
Outside of normal business hours – Meter read, install or turn on service (2.2.2)	\$50.00	\$75.00
Outside of normal business hours – other services (2.2.3)		Hourly cost
Reconnection at pole (4.5.1)	\$87.50	\$100.00
On site energy evaluation (4.6)	\$50.00	\$90.00
Joint site visit (6.2.3)	\$30.00 metro \$75.00 outside \$30/hr after 30 minutes	\$70.00 (min.) in all areas, Actual hourly cost after 30 minutes
Meter test (6.5)	\$25.00	\$30.00 in shop \$100.00 in field

1 **Q. ARE YOU REQUESTING ANY OTHER CHANGES IN SCHEDULE 1**
2 **THAT IMPACT THE REVENUE OF APS?**

3 A. Yes, APS is requesting approval to provide an electronic rather than paper bill to
4 a customer upon the customer's request. In addition to the fact that some
5 customers simply prefer to receive electronic bills, elimination of the paper bill
6 will provide savings to APS by reducing postage and printing costs. Thus, to
7 encourage customers to opt for an electronic bill in lieu of a paper bill, APS will
8 provide a one time \$5.00 incentive. A customer may switch back to the paper
9 bill option without penalty. However, each customer will be entitled to only one
10 \$5.00 incentive.

11 **Q. PLEASE DESCRIBE THE NON- REVENUE SCHEDULE 1 CHANGES.**

12 A. APS is proposing that the process for establishing residential customer
13 creditworthiness be modified. In the past, other utilities would provide
14 customers with a letter that described the creditworthiness of a customer. APS
15 would accept such a letter and, if appropriate, would waive security deposits.
16 Today, however, many utilities have discontinued the practice of providing
17 creditworthiness letters. In lieu of the letter, APS began the practice of
18 requesting a report from credit rating agencies like virtually all other businesses
19 do and using that information to determine whether a security deposit was
20 needed. The proposed change affirms this current industry practice.

21 **Q. WHAT OTHER CHANGES HAVE YOU PROPOSED FOR SCHEDULE**
22 **1.**

23 A. One of the ongoing issues that our field personnel face today is difficulty with
24 meter access. Inaccessible meters cause several problems. From the customer's
25 perspective, lack of meter access may limit rate choice. Some of our retail
26 schedules require that meters be reset after each monthly read. Without monthly

1 access, these rate options become unavailable to the customer. It also prevents
2 APS from providing monthly billings that are based on actual meter readings
3 rather than estimates. From APS' perspective, the Company needs unassisted
4 access to meters for maintenance, testing, and other purposes. To enforce the
5 meter access requirements, APS is requesting the right to terminate service to a
6 customer if after six months of good faith efforts to resolve access issues access
7 remains restricted. The change also allows APS to offer, at the customer's
8 expense, a remotely read meter option for those customers who cannot provide
9 unassisted access.

10 **Q. ARE YOU REQUESTING ANY OTHER CHANGES IN SCHEDULE 1**
11 **THAT PERTAIN TO METERING AND METER READING?**

12 A. Yes. APS is also proposing to clarify language regarding power factor
13 requirements to better describe the requirements and potential remedies for the
14 Company if power factor requirements are not met.

15 **IV. SCHEDULE 3 - LINE EXTENSIONS**

16 **Q. WHAT IS SCHEDULE 3?**

17 A. Schedule 3 is APS' line extension policy. The current policy includes three
18 main elements that define conditions governing line extensions. These elements
19 are: (1) a footage allowance for residential extensions, (2) a revenue test for
20 extensions when the construction cost is under \$25,000, and (3) an economic
21 feasibility analysis for extensions when the cost exceeds \$25,000 or that are not
22 subject to the footage allowance or revenue test. Also, when I refer to
23 "residential" customers, I mean individual residential premises as opposed to
24 subdivision developers. Line extensions for residential subdivisions being
25
26

1 constructed by developers are evaluated under the revenue test or an economic
2 feasibility analysis.

3
4 **Q. PLEASE DESCRIBE THE CHANGES THAT ARE PROPOSED IN THE POLICY.**

5 A. The current line extension policy is based on one that originated in 1954. Under
6 the footage allowance portion of the current extension policy, permanent
7 residential customers are provided with a 1,000-foot free construction allowance.
8 If the customer's extension exceeds 1,000 feet but is less than 2,000 feet or the
9 construction cost exceeds \$25,000, the policy requires that the customer sign an
10 extension agreement and provide a refundable advance. Under our proposed
11 new policy, the footage basis is eliminated and permanent residential customers
12 will be given a dollar-based equipment allowance. If the construction cost of the
13 extension exceeds the allowance, the customer will be required to make a non-
14 refundable contribution in aid of construction. This change only applies to
15 permanent residential extensions where the construction cost is under \$25,000.
16 Line extensions where the cost is over \$25,000 will be evaluated under an
17 economic feasibility analysis discussed below, as applicable.

18
19 **Q. HOW DOES THE CURRENT APS POLICY COMPARE WITH INDUSTRY TRENDS?**

20 A. I am currently the Vice-Chairman of the Edison Electric Institute's Economic
21 Regulation and Competition Committee and the topic of line extension policies
22 is an agenda item at almost every semi-annual meeting. We have extensive
23 discussions regarding the application and administration of line extension
24 policies and, almost universally, utility companies struggle with developing
25 policies that are fair to new customers, existing customers and the companies.
26 Tracking extension contracts and administering extension policies are difficult

1 issues that most utilities face. Utilities are moving from footage-based policies
2 to construction-allowance based policies in order to improve extension policy
3 administration and more correctly recover costs. The construction allowance
4 approach recognizes that construction costs for individual customer locations
5 can vary widely. APS believes that our proposed change is more equitable and is
6 consistent with the current trends in the industry.

7
8 **Q. ARE THERE OTHER REASONS SUPPORTING A CHANGE TO AN
CONSTRUCTION ALLOWANCE?**

9 A. The primary reason to convert to a construction allowance approach is to
10 recognize that construction costs can vary significantly for each individual
11 extension. The Company's service territory is very diverse. There are densely
12 populated areas, rural areas, desert areas and mountainous areas. Because of this
13 diversity and also to recognize that some extensions are overhead while others
14 are underground, an allowance based on a fixed investment amount is fairer.
15 Under a footage allowance-based approach, the cost of a short, very expensive
16 extension results in an unfair burden on the rest of the Company's customers.

17 **Q. WHAT IS THE PROPOSED CONSTRUCTION ALLOWANCE UNDER
18 APS' REVISED LINE EXTENSION POLICY?**

19 A. APS is proposing a residential extension allowance of \$3,500 per permanent
20 residential customer.

21 **Q. HOW WAS THIS AMOUNT DETERMINED?**

22 A. APS examined several approaches. In other states that have adopted the
23 construction allowance approach, the allowance is based on the average net
24 embedded distribution investment per customer based on a cost of service study.
25 The underlying theory is that this average is the investment on which retail rates
26

1 are designed. For APS, the average net embedded investment, excluding
2 substation plant investment, for residential customers is approximately \$1,500.
3 We also analyzed the average plant investment from a reproduction cost basis
4 and determined that value to be approximately \$2,600. We elected to apply a
5 more generous \$3,500 allowance for several reasons. First, this allowance
6 equates to the cost of a typical 500-feet underground extension, which is
7 comparable to the allowance provided by other Arizona utilities. Second, we
8 wanted to ease the transition from the current 1000-feet allowance. Today, the
9 construction costs for a 1000-feet overhead extension is approximately \$10,000.
10 Thus, simply converting the existing footage allowance to an equivalent
11 construction allowance would not solve the problem of excessive investment
12 needed to serve one customer and would not accurately capture average
13 embedded costs. However, because APS will no longer provide construction
14 advance refunds for residential extensions under \$25,000, the proposed
15 allowance will ease the transition to the new method.

16
17 **Q. HOW WILL THE EXTENSION POLICY BE APPLIED TO NON-RESIDENTIAL APPLICATIONS?**

18 **A.** We will continue to use a revenue test for non-residential extensions where the
19 construction cost does not exceed \$25,000 and an economic feasibility based
20 analysis for extensions when the cost exceeds \$25,000. The revenue test is based
21 on a simple relationship between expected revenue from a customer and the
22 extension cost. Currently, if two times the customer's expected annual revenue
23 is more than the cost of the extension less nonrefundable contributions, the
24 extension is provided for free. If expected revenue does not meet the revenue
25 test, an advance is received from the customer. The economic feasibility-based
26

1 analysis is a more exhaustive approach that entails examining the return on
2 investment for a particular extension.

3
4 **Q. DOES APS PROPOSE TO CHANGE THE METHODOLOGIES USED
TO COMPUTE THE REVENUE BASIS TEST OR THE ECONOMIC
FEASIBILITY TEST?**

5 A. Yes. Historically, the tests were based on total expected bundled-rate sales
6 revenue from an individual customer in case of a single customer or customers
7 in a subdivision. In the future, APS will perform the analysis based on the
8 revenue generated by the distribution component of retail rates. Thus, the
9 economic analysis will make no distinction between Standard Offer customers
10 and Direct Access customers. With this change, the multiplier for the revenue
11 test will be six. In other words, the extension will be free if six times the annual
12 distribution revenue received from the extension is equal to or greater than the
13 extension cost.
14

15 **Q. ARE YOU PROPOSING ANY OTHER CHANGES TO THE ECONOMIC
FEASIBILITY REQUIREMENTS?**

16 A. Yes, current policy allows APS to assess a facilities charge in cases where an
17 extension is not economically feasible even after we receive an advance.
18 Currently, the facilities charge is collected on an annual basis until such time as
19 the extension becomes economically feasible without the facilities charge. The
20 majority of facilities charge agreements are needed for no more than a few
21 years. The few agreements that continue for longer periods return little revenue
22 and are difficult to administer. Thus, APS is proposing two customer options.
23 The customer may elect to pay the facilities charge for a five-year period or
24 make a one time payment based on the present worth of the five-year facilities
25 charge income stream. The facilities charge would be reduced, eliminated, or
26

1 refunded if the economics of the extension improve. These modifications reflect
2 a change in practice in administering the extension policy but do not require
3 changes to the policy language.

4 **Q. IS APS PROPOSING TO MAKE ANY CHANGES TO THE**
5 **METHODOLOGY USED TO DETERMINE THE ECONOMIC**
6 **FEASIBILITY OF REAL ESTATE DEVELOPMENTS?**

7 **A.** Yes, in addition to using only distribution revenue and expenses in the economic
8 feasibility analysis, APS is changing the methodology used to estimate sales
9 volume. Currently, the analysis assumes that all residential customers in a
10 development are all-electric. This is no longer a valid assumption. For example,
11 in most new residential developments natural gas is available and most new
12 homes are dual-fuel. In the Company's new model, APS will run the economic
13 analysis under a dual-fuel or all-electric basis, depending on the specifics of the
14 development. If the developer offers natural gas appliances, we will use the
15 dual-fuel option. We will use the all-electric option only if natural gas is
16 unavailable. The economic analysis for commercial customers is presently
17 performed based on expected electrical load so there will be no change in the
18 analysis for commercial customers.

19 **Q. ARE THERE ANY OTHER CHANGES PROPOSED FOR THE LINE**
20 **EXTENSION POLICY?**

21 **A.** Yes, we have made several editorial changes to the schedule. APS is also
22 proposing to eliminate some language regarding line extensions to irrigation
23 customers. The current version of Schedule 3 includes refund and advance
24 provisions that are unique to irrigation customers. All future non-agricultural
25 irrigation extensions will be handled under the revenue test or economic
26 feasibility analyses discussed earlier. Agricultural irrigation extensions will be

1 funded through customer advances that are subject to refund. Also, APS is
2 proposing to eliminate language that was specific to customers served on the
3 network distribution systems such as the network that exists in downtown
4 Phoenix and to add language that provides for a customer contribution when the
5 customer requests an additional primary feeder. This would be applicable to
6 customers who have a high reliability requirement and request special service.
7 Finally, language has been added to allow customers to design and construct
8 facilities that would otherwise be designed and constructed by APS. This
9 provides customers with the option of providing facilities to APS in lieu of
10 providing construction advances for APS construction. Any facilities designed
11 and constructed by customers must be in accordance with APS specifications
12 and will be inspected by APS.

13 V. SCHEDULE 4 – TOTALIZING

14 Q. **PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE 4.**

15 A. Schedule 4 addresses policies relative to totalizing of meter readings. It is
16 applied when customers at a single premise receive service through multiple
17 service entrances. Historically, totalizing has only been applicable to general
18 service customers with three-phase service. Recently, however, APS has had a
19 few instances where totalizing could be applicable to residential customers. The
20 proposed changes merely make that option available to residential customers
21 and single-phase commercial customers. APS is also proposing language to
22 address the possibility that a customer with meters that are totalized may request
23 that the meters no longer be totalized. This possibility is not addressed in the
24 current version of Schedule 4. We are also removing the current prohibition on
25 same-site remote totalizing.
26

1 VI. SCHEDULE 7 – METER PERFORMANCE MONITORING PLAN

2 Q. **PLEASE DESCRIBE THE PROPOSED CHANGES IN SCHEDULE 7.**

3 A. The proposed changes to the Company's Meter Performance Monitoring Plan
4 service schedule consist of editorial changes to reflect current American
5 National Standards Institute ("ANSI") standards. The proposed changes also add
6 language for performance monitoring of solid-state meters.

7 VII. SCHEDULE 10 – TERMS AND CONDITIONS FOR DIRECT ACCESS

8 Q. **PLEASE DESCRIBE THE PROPOSED CHANGES FOR SCHEDULE 10**

9 A. This is the first revision of Schedule 10 since it became effective in 1998. The
10 proposed changes are largely editorial. For example, all references to "APS"
11 have been changed to "Company" to be consistent with the other service
12 schedules. Also, we eliminated language that addressed the phase-in of
13 competition, as that language is no longer necessary. None of the proposed
14 changes impact the ability of Energy Service Providers or Direct Access
15 customers to opt for competitive choice in APS' service territory.

16
17 VIII. SCHEDULE 15 – SPECIALIZED METERING

18 Q. **PLEASE DESCRIBE THE PROPOSED CHANGES IN SCHEDULE 15**

19 A. Schedule 15 was titled "Conditions Governing the Providing of Electric KWH
20 Pulses." APS is proposing to change the title to "Conditions Governing the
21 Provision of Specialized Metering" to reflect changes that broaden the scope of
22 the schedule. A wider scope is needed to reflect the state of the art of metering.
23 For example, the existing language did not address the use of Interval Data
24 Recording meters. The revisions to Schedule 15 also better define
25 responsibilities between APS and the customer regarding the cost responsibility
26 for specialized metering and addresses technical aspects of meter installations.

1 Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

2 A. Yes it does.

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Mr. Rumolo has held his current position at Arizona Public Service Company for approximately three years. Prior to assuming that position, he served as the Manager of Transmission and Market Structure Assessment for Pinnacle West Energy Corporation ("PWEC"). Before joining PWEC, Mr. Rumolo had a 15-year career as a consultant with Resource Management International, Inc., where he provided utility rate and engineering consulting services to utility clients across the United States and overseas. He began his career providing consulting services to utility clients when he joined the firm of Miner and Miner Consulting Engineers in Greeley, Colorado where he became the Manager of Planning and Rates. He later became a partner in Electrical

1 Systems Consultants where he focused on cost of service and rate analyses, as well as
2 transmission and distribution planning.

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APPENDIX B



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

- 1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.
- 1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.
- 1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.
- 1.4 Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to Company's distribution system.

2. Establishment of Service

- 2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and sign Company's standard form of application for service or a contract before service is supplied by Company.
 - 2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.
 - 2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.
 - 2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.
- 2.2 Service Establishment Charge - A service establishment charge of \$25.00 for residential and \$35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month. Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.

- 2.2.1 The customer may additionally be required to pay a trip charge of \$17.50 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to meter panel.
- 2.2.2 The customer may additionally be required to pay an after-hour charge of \$75.00 should the customer request service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established during a period other than regular working hours, or on the same day of their request, regardless of the time the order may be worked by Company.
- 2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be billed at current hourly rates as determined by Company.
- 2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of \$10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.
- 2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:
 - 2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.
 - 2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.
 - 2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.6 hereof.
 - 2.4.4 The applicant is known to be in violation of Company's tariff.
 - 2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.
 - 2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.
 - 2.4.7 Service is already being provided at the address for which the applicant is requesting service.
 - 2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill.
 - 2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 Establishment of Credit or Security Deposit

- 2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new applicant for residential service if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.

2.5.1.3 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

- 2.5.2 Residential Establishment of Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

- 2.5.3 Nonresidential Establishment of Security Deposit - All nonresidential customers may be required to:

2.5.3.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.3.2 Provide a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Reestablishment of Security Deposit

- 2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 2.6.2 Nonresidential - Company may require a nonresidential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a six (6) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data.

2.7 Security Deposits

- 2.7.1 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by the Company:
- 2.7.1.1 If the customer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,
- 2.7.1.2 If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,
- 2.7.1.3 If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that APS is providing bundled electric service.
- 2.7.2 Separate security deposits may be required for each service location.
- 2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.
- 2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.
- 2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.
- 2.7.6 Residential security deposits shall not exceed two (2) times the customer's average monthly bill as estimated by Company for the services being provided by the Company.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless Customer has filed bankruptcy in the last 12 months.
- 2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by the Company.
- 2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.
- 2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.
3. Rates
- 3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.
- 3.2 Rate Selection - The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is being served on a Standard Offer rate, Company will use reasonable care in initially establishing service to the customer under the most advantageous Standard Offer rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.
- 3.3 Standard Offer Optional Rates - Certain optional Standard Offer rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective initially or after service has been established. A customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company. Billing under the alternate rate will become effective from the next meter reading, or when the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 3.4 Direct Access rate selection will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.
- 3.5 Any customer making a Direct Access rate selection may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer.

4. Billing and Collection

- 4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.
- 4.1.1 Company normally meters and bills each site separately; however, adjacent and contiguous sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.
- 4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.
- 4.2 Collection Policy - The following collection policy shall apply to all customer accounts:
- 4.2.1 All bills rendered by Company are due and payable no later than fifteen (15) days from the billing date. Any payment not received within this time frame shall be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved services. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.
- 4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.
- 4.3 Responsibility for Payment of Bills
- 4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until the Company has had reasonable time to process the disconnect request.
- 4.3.2 When an error is found to exist in the billing rendered to the customer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Any refunds to customers resulting from overbillings will be made promptly upon discovery by Company. Underbillings by Company shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.
- 4.3.3 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of up to \$10.00 per customer to customers who elect to pay their bills using Company's electronically transmitted payment options.
- 4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of \$5.00 per customer for a customer electing to forego the presentation of a paper bill.
- 4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified check, or other means which guarantee the customer's payment to Company.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 4.4.1 The customer shall be charged a fee of \$15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.
 - 4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.
 - 4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.
 - 4.5 Field Call Charge - Company may require payment of a Field Call Charge of \$15.00 when an authorized Company representative travels to the customer's site to accept payment of a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.
 - 4.5.1 If a termination is required at the pole, a reconnection charge of \$100.00 will be required; if the termination is in underground equipment, the reconnection charge will be \$125.00.
 - 4.5.2 To avoid termination of service, the customer may make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.
 - 4.6 On-site Evaluation - Company may require payment of an On-site Evaluation Charge of \$90.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of if the customer actually implements Company suggestions.
5. Service Responsibilities of Company and Customer
- 5.1 Service Voltage - Company will deliver electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F.
 - 5.2 Responsibility: Use of Service or Apparatus
 - 5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.
 - 5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.
- 5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.
- 5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

- 5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.
- 5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

- 5.4 Company Access to Customer Sites - Company's authorized agents shall have unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any existing rate options where access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored.

5.5 Easements

- 5.5.1 All suitable easements or rights-of-way required by Company for any portion of the extension which is on sites owned, leased or otherwise controlled by the customer shall be furnished in Company's name by the customer without cost to Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense.

5.6 Load Characteristics – The customer shall exercise reasonable care to assure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. The deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery. Except for Company's meters and special equipment, the customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at <http://esp.apsc.com/resource/metering>.

6.1.2 If telephone lines or any other devices are required to read the customer's meter, the customer is responsible for the installation, maintenance, and usage fees at no cost to Company.

6.1.3 Where a customer requests, and Company approves, a special meter reading device to accommodate the customer's needs, the cost for such additional equipment shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Load Serving ESP or their authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will be charged the replacement costs less five (5) years depreciation plus an administration fee of fifteen percent (15%).



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 6.2.2 Company will lease lock ring keys to Load Serving ESP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of \$70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the ESP's agent, Company may, rather than leasing additional lock ring keys, require the ESP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the Load Serving ESP and/or their authorized agents are:
- 1) No longer permitted to remove Company meters pursuant to conditions of the Company's Schedule 10;
 - 2) No longer authorized by the Arizona Corporation Commission to provide services; or
 - 3) The ESP Agreement has been terminated.
- 6.2.3 If the Load Serving ESP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of \$70.00 per site. Company may assess an additional charge, based on the current hourly rate as determined by Company, for joint site meetings that exceed thirty (30) minutes. In the event Company must temporarily replace the ESP's meter and/or associated metering equipment as necessary during emergency situations or to restore power to a customer, the above charges may apply.
- 6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider. For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors. For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry credentials which they will show on request.
- 6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company or the Load Serving ESP pursuant to the terms and conditions of Company's Schedule 10. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.
- 6.4.1 For Standard Offer customers, or where Company is the Meter Reading Service Provider (MRSP), the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 6.4.2 If there is evidence of meter tampering or energy diversion, the customer will be billed for the estimated energy consumption that would have registered had all energy usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer may also be charged the cost of the investigation as determined by Company.
- 6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the ESP.
- 6.4.4 Customer will be billed for the estimated energy and demand that would have registered had the meter been operating properly. Where Company is the MRSP, Company shall, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is \$20.00 and may be charged to the customer or the ESP, provided that the original reading was not in error.
- 6.4.5 Where the ESP is the Meter Service Provider (MSP) or (MRSP), and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may obtain the data, or may estimate the billing determinants. The charge for such reread is \$20.00 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP \$30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and \$100.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

- 6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.
- 6.6.2 Residential Apartment Complexes, Condominiums and Other Multiunit Residential Buildings - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205.

7. Termination of Service

- 7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Alan Propper
Title: Director of Pricing
Original Effective Date: December, 1951

A.C.C. No. XXXX
Canceling A.C.C. No. 5447
Schedule 1
Revision No. 30
Effective: XXXXXXXX



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.
- 7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.
- 7.1.3 The customer's breach of a written contract for service.
- 7.1.4 Failure of the customer to comply with Company's deposit requirements.
- 7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.
- 7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.
- 7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.
- 7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.
- 7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:
 - 7.2.1 The existence of an obvious hazard to the health or safety of persons or property.
 - 7.2.2 Company has evidence of meter tampering or fraud.
 - 7.2.3 Company has evidence of unauthorized resale or use of electric service.
 - 7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.
- 7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.
- 8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.

For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.
10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

- 1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the cCustomer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.
- 1.2 These Terms and Conditions shall be considered a part of all Standard Offer and Direct Access rate schedules, except where specifically changed by a written agreement.
- 1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.
- 1.4 The Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by the Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to APS' Company's distribution system.

2. Establishment of Service

- 2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and sign Company's standard form of application for service or a contract before service is supplied by Company.
 - 2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the cCustomer shall be deemed to constitute a service agreement by and between Company and the cCustomer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.
 - 2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.
 - 2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 2.2 Service Establishment Charge - A service establishment charge of \$25.00 for residential and \$35.00 non-residential ~~for electric service and the appropriate tax adjustment~~ plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the cCustomer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month. Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill. The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.
- 2.2.1 The customer may additionally be required to pay a trip charge of \$17.50 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to meter panel.
- 2.2.2.2 The cCustomer may additionally be required to pay an after-hour charge of \$5075.00 should the cCustomer request service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established during a period other than regular working hours, or on the same day of their request, regardless of the time the order may be worked by Company.
- 2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be billed at current hourly rates as determined by Company.
- 2.3 Direct Access Service Request (DASR) - A ~~Ddirect Access Sservice Rrequest~~ charge of \$10.00 plus any applicable tax adjustment ~~and the appropriate tax adjustment~~ will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.
- 2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:
- 2.4.1 The aApplicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to with Company for payment.
- 2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.
- 2.4.3 The aApplicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.6 hereof.
- 2.4.4 The aApplicant is known to be in violation of Company's tariffs.
- 2.4.5 The aApplicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the aApplicant and which have been specified by Company as a condition for providing service.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 2.4.6 The aApplicant falsifies his or her identity for the purpose of obtaining service.
- 2.4.7 Service is already being provided at the address for which the aApplicant is requesting service.
- 2.4.8 Service is requested by an aApplicant and a prior cCustomer living with the aApplicant owes a delinquent bill.
- 2.4.9 The aApplicant is acting as an agent for a prior cCustomer who is deriving benefits of the service and who owes a delinquent bill.
- 2.4.10 The aApplicant has failed to obtain all required permits and/or inspections indicating that the aApplicant's facilities comply with local construction and safety codes.

2.5 Establishment of Credit or Security Deposit

- 2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new aApplicant for residential service if the aApplicant is able to meet any of the following requirements:

- 2.5.1.1 The aApplicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

- 2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company. Applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received which states Applicant had a timely payment history at time of service discontinuation.

- 2.5.1.3 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to the Company or a surety bond as security for Company in a sum equal to the required deposit.

- 2.5.2 Residential Establishment of Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the aApplicant left an unpaid final bill owing to another utility company, the aApplicant will be required to:

- 2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

- 2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

2.5.3 Nonresidential Establishment of Security Deposit - All nonresidential customers may be required to:

2.5.3.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.3.2 Provide a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential cCustomer to establish or re-establish a security deposit if the cCustomer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential cCustomer to establish or re-establish a security deposit if the cCustomer becomes delinquent in the payment of two (2) or more bills within a six (6) consecutive month period or if the cCustomer has been disconnected for non-payment during the last twelve (12) months, or when the cCustomer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all cCustomers of the Arizona Corporation Commission's complaint process should the cCustomer dispute the deposit based on the financial data.

2.7 Security Deposits

2.7.1 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by the Company:

2.7.1.1 If the cCustomer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,

2.7.1.2 If the cCustomer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount, which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to the Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 2.7.1.3 If the ~~c~~Customer chooses to change from Direct Access services to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that APS is providing bundled electric service.
- 2.7.2 Separate security deposits may be required for each service location.
- 2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of ~~c~~Customer obligation under the agreement for service.
- 2.7.4 Cash deposits held by ~~the~~ Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the ~~c~~Customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.
- 2.7.5 If the ~~c~~Customer terminates all service with Company, the security deposit may be credited to the ~~c~~Customer's final bill.
- 2.7.6 Residential security deposits shall not exceed two (2) times the ~~c~~Customer's average monthly bill as estimated by Company for the services being provided by the Company.
- 2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the ~~c~~Customer has not been delinquent more than twice, unless Customer has filed bankruptcy in the last 12 months.
- 2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the ~~c~~Customer's maximum monthly billing as estimated by ~~the~~ Company for the service being provided by the Company.
- 2.7.7.1 Deposits and non-cash deposits on file with ~~the~~ Company will be reviewed after twenty-four (24) months of service and will be returned provided the ~~c~~Customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the ~~c~~Customer's financial condition warrants extension of the security deposit.
- 2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

3. Rates

- 3.1 Rate Information - Company shall provide, in accordance ~~to with A.A.C. Commission Rule,~~ R14-2-204, a copy of any rate schedule applicable to that ~~c~~Customer for the requested type of service. In addition, Company shall notify its ~~c~~Customers of any changes in Company's tariffs affecting those ~~c~~Customers.
- 3.2 Rate Selection -- ~~The c~~Customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the ~~c~~Customer is being served on a Standard Offer rate, the Company will use reasonable care in initially establishing service to ~~the c~~Customer under the most advantageous Standard Offer rate schedule applicable to ~~the c~~Customer. However, because of varying ~~c~~Customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that ~~the c~~Customer would have paid less for service had ~~the c~~Customer been billed on an alternate applicable rate or provision of that rate.
- 3.3 Standard Offer Optional Rates -- Certain optional ~~S~~standard ~~O~~ffer rate schedules applicable to certain classes of service allow ~~the c~~Customer ~~the~~ option to select the rate schedule to be effective initially or after service has been established. A ~~c~~Customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company. Billing under the alternate rate will become effective from ~~or after~~ the next meter reading, or when the appropriate metering equipment is installed ~~place~~. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which ~~the c~~Customer is provided service specifies a term, ~~the c~~Customer may not exercise its option to select an alternate rate schedule until expiration of that term.
- 3.4 Direct Access rate selection will be effective upon the next ~~regular~~ meter read date if ~~the direct access service request~~ DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a ~~direct access service request~~ DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service ~~in accordance with the rules, regulations, and orders of the Commission.~~
- 3.5 Any customer making a Direct Access rate selection may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access for the succeeding twelve (12) month period. If a customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 ~~The Company normally meters and bills each premise site separately; however, adjacent and contiguous premises sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single premise site as specified in Company's Schedule #4.~~ Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 ~~The cCustomer's service installation will normally be arranged to accept only one type of standard service at one point of delivery to enable service measurement through one meter. If the cCustomer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.~~

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by the Company are due and payable no later than fifteen (15) days from the billing date. Any payment not received within this time frame shall be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the cCustomer's service for: i) non-payment of any Arizona Corporation Commission approved services provided by Company, including but not limited to ii) delinquent service bills; iii) non-payment of service establishment charges; iv) non-payment of security deposits; v) non-payment of meter test charges; vi) non-payment of any dishonored payment charges; vii) non-payment of late charges; viii) non-payment of collection charges. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. Section R 14-2-201.9 Definition #9 of the Arizona Administration Code, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the cCustomer is unwilling to make payment arrangements with that are acceptable to Company for payment, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the cCustomer for the same class of service. The failure of the cCustomer to pay the active account shall result in the suspension or termination of service thereunder.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

4.2.3 Unpaid charges incurred prior to the cCustomer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The cCustomer is responsible for the payment of bills until service is ordered discontinued and the Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until the Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the cCustomer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Any refunds to cCustomers resulting from adjusted overbillings will be made promptly upon discovery by Company. Underbillings by Company shall be billed to the cCustomer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.

4.3.3 Where Company is responsible for producing rendering the cCustomer's bill, Company may provide a one time incentive of up to \$10.00 per customer maximum to cCustomers who elect to pay their bills using the Company's SurePay electronically transmitted payment options.

4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of \$5.00 per customer for a customer electing to forego the presentation of a paper bill.

4.4 Dishonored Payments - If Company is notified by the cCustomer's financial institution that they will not honor a payment tendered by the cCustomer for payment of any bill because: (i) there are insufficient funds; (ii) the account has been closed; (iii) Customer has sent a "stop payment" request; or (iv) any other reason the financial institution will not honor Customer's payment, Company may require the cCustomer to make payment in cash, by money order, certified check, or other means which guarantee the cCustomer's payment to the Company.

4.4.1 The cCustomer shall be charged a fee of fifteen dollars (\$15.00) for each instance where the cCustomer tenders payment of a bill with a payment that is not honored by the cCustomer's financial institution.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 4.4.2 The tender of a dishonored payment shall in no way (i) relieve the cCustomer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.
- 4.4.3 Where the cCustomer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the cCustomer to make payment in cash, money order or cashier's check for the next ~~six (6)~~ twelve (12) consecutive months.
- 4.5 Field Call Charge - Company may require payment of a Field Call Charge of \$15.00 when an authorized Company representative travels to the cCustomer's ~~site~~ premises to accept payment of a delinquent account, notify of service termination, ~~or make payment arrangements or terminate the~~ service. This charge will only be applied for field calls resulting from the termination process.
- 4.5.1 If a termination is required at the pole, a reconnection charge of ~~\$87.50~~ \$100.00 will be required; if the termination is in underground equipment, the reconnection charge will be \$125.00.
- 4.5.2 To avoid ~~discontinuance~~ termination of service, the cCustomer may make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.
- 4.6 On-site Evaluation - Company may require payment of an On-site Evaluation Charge of ~~\$50.00~~ \$90.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of if the customer actually implements the Company suggestions.
5. Service Responsibilities of Company and Customer
- 5.1 Service Voltage - ~~The~~ Company will deliver electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C.R. 14-2-208.F.
- 5.2 Responsibility: Use of Service or Apparatus
- 5.2.1 ~~The cCustomer shall save and Company each shall save the other harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by the Company or the use thereof on the customer's their respective sides of the point of delivery. Company shall, however, have the right to suspend or terminate service in the event Company should learn of service use by the cCustomer under hazardous conditions.~~
- 5.2.2 The cCustomer shall exercise all reasonable care to prevent loss or damage to Company property installed on the cCustomer's premise site for the purpose of supplying service to the cCustomer.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 5.2.3 The cCustomer shall be responsible for payment for loss or damage to Company property on the cCustomer's premise-site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.
- 5.2.4 The cCustomer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.
- 5.2.5 The cCustomer shall be responsible for notifying Company of any failure in Company's equipment.
- 5.3 Service Interruptions: Limitations on Liability of Company
- 5.3.1 Company shall not be liable to the cCustomer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the cCustomer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The cCustomers needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.
- 5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other cCustomers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.
- 5.4 Company Access to Customer Premises Sites - Company's authorized agents shall have unassisted access to the cCustomer's premises sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. ~~Neglect or refusal on the part of Customer to provide reasonable and unassisted access shall be, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have unassisted access to the meter, then Company shall have sufficient cause for discontinuance of service by Company, or denial of any existing rate options where access is required.~~ The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter. However, all conditions existing prior to June 30, 1998 shall be grandfathered. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

5.5 Easements -

5.5.1 All suitable easements or rights-of-way required by Company for any portion of the extension which is on premises sites owned, leased or otherwise controlled by the cCustomer shall be furnished in Company's name by the cCustomer without cost to Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense.

5.6 Load Characteristics -- The cCustomer shall exercise reasonable care to assure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. The deviation from phase balance shall not be greater than ten percent (10%) at any time. The power factor of the load shall not be less than ninety percent (90%) lagging, but in no event leading, unless agreed to by Company. In the event that Customer does not maintain such power factor, at the option of Company, kVa may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

6. Metering and Metering Equipment

6.1 Customer Equipment- The cCustomer shall install and maintain all wiring and equipment beyond the point of delivery. Except for Company's meters and special equipment, the cCustomer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish and if an inspection or permit is if required by law or by Company, the same must be furnished by Customer.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 6.1.1 The ~~c~~Customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements ~~M~~manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's representative agent for the installation, ~~accessibility and maintenance~~ of Company's metering equipment. All updates to the Electric Service Requirements manual shall be provided to the ACC Staff in a timely manner. A current version of the Electric Service Requirements Manual is available on-line at <http://esp.apsc.com/resource/metering>.
- 6.1.2 If telephone lines or any other devices are required to read the ~~customer's~~ meter, the ~~c~~Customer is responsible for the installation, ~~and maintenance, and usage fees~~ at no cost to the Company.
- 6.1.3 Where a customer requests, and Company approves, a special meter reading device to accommodate the customer's needs, the cost for such additional equipment shall be the responsibility of the customer.

6.2 Company Equipment

- 6.2.1 A Load Serving Entity ~~ESP~~ or their authorized agents may remove the Company's metering equipment pursuant to the Company's Schedule 10. Meters not returned to the Company or returned damaged will be charged the replacement costs less ~~five (5) years~~ depreciation plus an administration fee of fifteen percent (15%). ~~Potential transformers (PTs) and current transformers (CTs) not returned to the Company or returned damaged will be charged net book value plus an administrative fee of fifteen (15) %.~~
- 6.2.2 The Company will lease lock ring keys to Load Serving Entities ~~ESP's~~ and/or their agents authorized to remove Company meters pursuant to the terms and conditions of the Company's Schedule 10 at a refundable charge of \$70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%)% of the issued keys within any twelve (12) month period due to loss by the ~~MSPE~~ ~~ESP's~~ agent, Company may, rather than leasing additional lock ring keys, require the ESP to arrange for a joint meet. All lock ring keys must be returned to APS Company within five (5) working days if the ~~L~~oad ~~S~~serving entity ~~ESP~~ and/or their authorized agents are:
- 1) No longer permitted to remove the Company's meters pursuant to conditions of the Company's Schedule 10;
 - 2) No longer authorized by the Arizona Corporation Commission to provide services; or;
 - 3) ~~Or if~~ The ESP Agreement has been terminated.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

6.2.3 If the Load Serving ESP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of \$3070.00 per site for the Phoenix metropolitan area and \$75.00 per site for all other areas. The Company may assess an additional charge, based on the current hourly rate as determined by Company, of \$30.00 per hour for joint site meetings that exceed thirty (30) minutes. In the event Company must temporarily replace the ESP's meter and/or associated metering equipment as necessary during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the cCustomer's side of the point of delivery except its meter. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider. For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors. For the mutual protection of the cCustomer and Company, only authorized employees or agents of the Company or the Load Serving Entity ESP are permitted to make and energize the connection between Company's service wires and the cCustomer's service entrance conductors. Such employees carry credentials which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the cCustomer will be measured by commercially acceptable measuring devices by the Company or the Load Serving ESP pursuant to the terms and conditions of APS-Company's Schedule 10. Except where it is impracticable impractical to meter loads, such as street lighting, security lighting, or special installations, in which case the consumption may be calculated will be determined by Company.

6.4.1 For Standard Offer cCustomers, or where Company is the Meter Reading Service Provider (MRSP), the readings of the meter will be conclusive as to the amount of electric power supplied to the cCustomer unless, there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the cCustomer will be billed for the estimated energy consumption that would have been registered had all energy usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer may also be charged the cost of the investigation as determined by Company.

6.4.3 If any meter after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the Electric Service Provider ESP.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 6.4.4 Customer will be billed for the estimated energy consumption and demand that would have been registered had the meter been operating properly. Where Company is the Meter Reading Service Provider (MRSP), Company shall, at the request of the cCustomer or the ESP, reread the cCustomer's meter within ten (10) working days after such request by the cCustomer. The cost of such rereads, which is \$10, is \$20.00 and may be charged to the cCustomer or the ESP, provided that the original reading was not in error.
- 6.4.5 Where the ESP is the Meter Service Provider (MSP) or Meter Reading Service Provider (MRSP), and the ESP and/or its' agent fails to provide the meter read data to APS Company pursuant to the Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, the Company may obtain the read data, or may estimate the billing determinants. The cost of charge for such reread, which is \$10 \$20.00, and may be charged to the ESP.
- 6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained meter upon cCustomer's or ESP's request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the cCustomer or the ESP \$25 \$30.00 for the costs of the meter test if the meter is removed from the site and tested in the meter shop, and \$100.00 if the meter remains on site and is tested in the field.
- 6.6 Master Metering
- 6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the utility Company as stated in R14-2-205 of the Corporation Commission's Administrative Rules and Regulations.
- 6.6.2 Residential Apartment Complexes, Condominiums and Other Multiunit Residential Buildings - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to the utility Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205 of the Corporation Commission's Administrative Rules and Regulations.
7. Termination of Service
- 7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any cCustomer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 7.1.1 A cCustomer's violation of any of the applicable rules of the Arizona Corporation Commission or Company's tariffs.
- 7.1.2 Failure of the cCustomer to pay a delinquent bill for services provided by the Company.
- 7.1.3 The cCustomer's breach of a written contract for service.
- 7.1.4 Failure of the cCustomer to comply with Company's deposit requirements.
- 7.1.5 Failure of the cCustomer to provide Company with satisfactory and unassisted access to Company's equipment. ~~However, all conditions existing prior to June 30, 1998 shall be grandfathered.~~
- 7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.
- 7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.
- 7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.
- 7.2 Without Notice - Company may without liability for injury or damage disconnect service to any cCustomer without advance notice under any of the following conditions:
 - 7.2.1 The existence of an obvious hazard to the health or safety of persons or property.
 - 7.2.2 Company has evidence of meter tampering or fraud.
 - 7.2.3 Company has evidence of unauthorized resale or use of electric service.
 - 7.2.4 Failure of the cCustomer to comply with the curtailment procedures imposed by Company during a supply shortage.
- 7.3 Restoration of Service - Company shall not be required to restore service until the conditions, which resulted in the termination, have been corrected to the satisfaction of Company.
- 8. Removal of Facilities - Upon the termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the cCustomer, and Company shall be under no further obligation to serve the cCustomer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the cCustomer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same cCustomer at the same location.



SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

For purposes of this Section notice to the cCustomer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the cCustomer at his/her last known address.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the cCustomer and Company, but no assignments by the cCustomer shall be effective until the cCustomer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.
10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.



SCHEDULE 3 CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and company facilities at the beginning point of an extension also as determined by Company.

The following policy governs the extension of overhead and underground electric facilities, and underground facilities as specified in Section 6, to customers whose requirements are deemed by Company to be usual and reasonable in nature.

1. CONSTRUCTION ALLOWANCE - RESIDENTIAL ONLY

1.1 GENERAL POLICY - Construction allowance extensions may be made only if all of the following conditions exist:

- 1.1.1 The applicant is a new permanent residential customer or group of new permanent residential customers. Customers specified in Section 4 below are not eligible for this allowance.
- 1.1.2 The total extension does not exceed a total construction cost of \$25,000.
- 1.1.3 No construction allowance will be permitted beyond the shortest practical route to the nearest practical point of delivery on each customer's site as determined by Company.

1.2 FREE EXTENSIONS - May be made if the conditions specified in Section 1.1 are met and such free extension does not exceed a total construction cost of \$3,500.

1.3 EXTENSIONS OVER THE FREE ALLOWANCE

For extensions which meet the conditions specified in Section 1.1 above, and which exceed the free Construction Allowance specified in Section 1.2, Company may extend its facilities up to the maximum allowed in Section 1.1.2 provided the customer or customers will sign an extension agreement and make a non-refundable contribution for the difference between the maximum allowed in Section 1.2 and Company's estimated cost of the extension.

2. REVENUE BASIS - NON-RESIDENTIAL

2.1 GENERAL POLICY - Revenue basis extensions may be made only if all of the following conditions exist:



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

2.1.1 Applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

2.1.2 Such extension does not exceed a total construction cost of \$25,000.

2.2 FREE EXTENSIONS

Such extension shall be free to the customer where the conditions specified in Section 2.1 herein are met and the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 2.1, above, and which exceed the free limits specified in Section 2.1.2, Company may extend its facilities up to a cost limitation of \$25,000, provided the customer or customers will sign an extension agreement and advance a sufficient portion of the construction cost so that the remainder satisfies the requirements of Section 2.2. Advances are subject to refund as specified in Section 5.

3. ECONOMIC FEASIBILITY BASIS

3.1 GENERAL POLICY - Extensions may be made on the basis of economic feasibility only if all of the following conditions exist:

3.1.1 The applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

3.1.2 The total construction cost exceeds \$25,000 except for extensions specified in Sections 4.4 or 7.7.

3.2 FREE EXTENSIONS

Such extensions shall be free to the customer where the conditions specified in Section 3.1 are met and the extension is determined to be economically feasible. "Economic feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer.

3.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 3.1, above, Company, after special study and at its option, may extend its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 3.2, provided such customers sign an extension agreement and advance as much of the construction cost and/or agree to pay such higher special rate (facilities charge) as is required to make the extension economically feasible. Advances are subject to refund as specified in Section 5.



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

4. OTHER CONDITIONS

4.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost. Advances are subject to refund as specified in Section 5.2. Non-agricultural irrigation pumping will be extended as specified in Section 2 or 3.

4.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the customer, then the customer, in advance of installation or construction, shall make a non-refundable contribution equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

4.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is doubtful, the customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 5.3.

4.4 REAL ESTATE DEVELOPMENT

Extensions of electric facilities within real estate developments including residential sub divisions, industrial parks, mobile home parks, apartment complexes, planned area developments, etc., may be made in advance of application for service by permanent customers, as specified in Section 3. Anticipated revenue for Residential Real Estate extensions shall be calculated from information provided by the developer.

4.4.1 MOBILE HOME PARKS - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the utility.

4.4.2 RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS AND OTHER MULTI UNIT RESIDENTIAL BUILDINGS - Company shall refuse service to all new construction and/or expansion of apartment complexes and condominiums unless the construction and/or expansion is individually metered by the utility. Master metering will only be allowed for buildings utilizing centralized heating, ventilation and/or air conditioning system where the contractor can provide an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations.



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

5. REFUNDS

5.1 REVENUE AND ECONOMIC FEASIBILITY BASIS REFUNDS

- 5.1.1 Customer advances over \$50.00 are subject to full or partial refund, provided that a survey based on conditions of the extension, not including laterals or extensions from the extension being surveyed as specified in Section 5.1.2 existing at the time of survey, results in an advance lower than the amount actually advanced. Except as provided for in Section 5.3, such surveys shall not be made for customers extended to under the basis specified in Section 4.1, 4.2, or 4.3. A survey will be conducted by Company five (5) years after signing the extension agreement under the extension policy in force at the time of the extension. Upon request, the customer will be entitled to intermediate surveys within the five (5) year period after the end of six (6) months following the date of signing the extension agreement and subsequent surveys at intervals of not less than one (1) year thereafter. Company will refund the difference between the amount advanced and the amount that would have been advanced had the advance been calculated at the time of survey. In no event shall the amount of any refund exceed the amount originally advanced.
- 5.1.2 Laterals or extensions from an extension being surveyed shall not be considered in the survey when the lateral or extension was extended on the basis "extensions over the free limits" of Sections 2.2 or 3.2, or is not connected directly to the extension being surveyed. In real estate developments extended to under the basis specified in Section 4.4, the survey may include laterals and extensions to serve permanent customers located within the real estate development described in the extension agreement for the extension being surveyed.
- 5.1.3 In lieu of surveys, Company will determine the refund based on the number of permanent connections to the extension for residential real estate development. In such event, Company shall specify in the extension agreement the amount of refund per permanent customer connection.

5.2 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

Customer advances over \$50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.3 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over \$50.00 are subject to full or partial refund pursuant to surveys based on the Revenue or Economic Feasibility Basis as specified in Section 5.1.1. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the customer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

5.4. GENERAL REFUND CONDITIONS

- 5.4.1 Customer advances of \$50.00 or less are not subject to refund.
- 5.4.2 No refund will be made to any customer for an amount more than the unrefunded balance of the customer's advance.
- 5.4.3 Any unrefunded balance of the customer's advance shall become nonrefundable five (5) years from the date of Company's receipt of the advance.
- 5.4.4 Company reserves the right to withhold refunds to any customer whose account is delinquent and apply these refund amounts to past due bills.

6. UNDERGROUND CONSTRUCTION

- 6.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

- 6.1.1 The extension meets feasibility requirements as specified in Sections 1, 2, 3, or 4.
- 6.1.2 The customer or developer provides all earthwork including, but not limited to, trench, boring or punching, conduits, backfill, compaction, and surface restoration in accordance with Company specifications.

(Company may provide all earthwork and the customer or developer will make a nonrefundable contribution equal to the cost of such work provided by Company.)

- 6.2 THREE-PHASE UNDERGROUND CONSTRUCTION - Where it is determined that three phase is required to serve the customer, Company may install three-phase facilities if the conditions specified in Section 6.1 are met, and the customer provides the following:

- 6.2.1 Installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications. In lieu of providing conduits, the customer may provide a nonrefundable contribution equal to the estimated difference in cost between overhead and underground facilities.
- 6.2.2 A nonrefundable contribution for excess service footage required by the customer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.
- 6.2.3 Transformer pad and secondary conduits in accordance with Company specifications. (Company may provide pad and conduits, and the customer or developer will make a non-refundable contribution equal to the cost of such work provided by Company.)



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

7. GENERAL CONDITIONS

7.1 VOLTAGE

The extension will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located.

7.2 THREE PHASE

Extensions for three phase service can be made under this extension policy where the customer has installed major three phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVa demand shall qualify for three phase. If the estimated load is less than the above horsepower or connected kVa specifications, Company may, at its option and when requested by the customer, serve three phase and require a nonrefundable contribution equal to the difference in cost between single phase and three phase construction, but in no case less than \$100.

7.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

7.4 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by Customer or developer.

7.5 OWNERSHIP

Except for customer-owned facilities, all construction, including that for which customers have made advances and/or contributions, will be owned, operated and maintained by Company.

7.6 MEASUREMENT AND LOCATION

7.6.1 Measurement must be along the proposed route of construction.

7.6.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

7.6.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.



SCHEDULE 3 CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

7.7 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when Customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contact arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

7.8 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way nonstandard, as determined by Company, or if unusual obstructions are encountered, the customer will make a non-refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

7.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the customer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

7.10 RELOCATIONS AND/OR CONVERSIONS

- 7.10.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics, providing the customer makes a nonrefundable contribution equal to the total cost of relocation or conversion.
- 7.10.2 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the customer's convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine the customer's advance on the basis specified in Section 2 or 3.

7.11 CHANGING OF MASTER METER TO INDIVIDUAL METER

Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on basis specified in Section 2 or 3.



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

7.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 2 or 3.

7.13 DESIGN DEPOSIT

Any applicant requesting Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction; otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

7.14 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

7.15 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

7.16 INTEREST

All advances made by the customer to Company in aid of construction shall be non-interest bearing.

7.16 EXTENSION AGREEMENTS

All line extensions requiring payment by the customer shall be in writing and signed by both the customer and Company.

7.17 ADDITIONAL PRIMARY FEED

Company will provide an additional primary (alternate) feed as requested by the customer provided the customer pays the added cost for the additional feed as a nonrefundable contribution in aid of construction and pays the applicable rate for the additional feed requested.



SCHEDULE 3 CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Application for Provision of electric service from Arizona Public Service Company (Company) Company's electric service often involves may require construction of new facilities or upgrades to existing facilities for various distances and costs depending Costs for construction depend on the upon ~~Customer's~~ location, load size, and load characteristics. With such variations, it is necessary to establish This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Footage Construction allowance and revenue basis methodologies are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within these footage construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and company facilities at the beginning point of an extension, as also as determined by Company.

The following policy governs the extension of overhead and underground electric facilities, and underground facilities as specified in Section 6-, to customers whose requirements are deemed by Company to be usual and reasonable in nature.

1. FOOTAGE BASIS CONSTRUCTION ALLOWANCE - RESIDENTIAL ONLY

1.1 GENERAL POLICY - Footage basis Construction allowance extensions may be made only if all of the following conditions exist:

1.1.1 The aApplicant will be a new permanent residential cCustomer or group of new permanent residential cCustomers. Customers specified in Section 4 below are not eligible for this allowance basis.

1.1.2 The total extension does not exceed a total construction cost of \$25,000. 2,000 feet per Customer and under no circumstance can the total allowable distance exceed 10,000 feet.

1.1.3 No construction allowance footage will be permitted beyond the shortest practical route to the nearest practical point of delivery on each cCustomer's premises as determined by Company.

1.1.4 Such extension does not exceed a total construction cost of \$25,000.

1.2 FREE EXTENSIONS - May be made if the conditions specified in Section 1.1 are met and such free extension does not exceed a total construction cost of \$3,500.

1.2.1 Such free extension will be limited to a maximum of 1,000 feet per new permanent residential Customer.

1.2.2 Free allowance for the total extension will be 1,000 feet per Customer regardless of Customer's location along the route of extension.



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

1.3 EXTENSIONS OVER THE FREE DISTANCE ALLOWANCE

For extensions which meet the conditions specified in Section 1.1, above, and which exceed the free Construction Allowance distance specified in Section 1.2, Company may extend its facilities up to the maximum allowed in Section 1.1.2 provided the cCustomer or cCustomers will sign an extension agreement and advance the cost of such additional footage. Advances are subject to refund as specified in Section 5 make a non-refundable contribution for the difference between the maximum allowed in Section 1.2 and Company's estimated cost of the extension.

2. REVENUE BASIS

2.1 GENERAL POLICY - Revenue basis extensions for non-residential customers may be made only if all of the following conditions exist:

2.1.1 Applicant is or will be a permanent cCustomer or group of permanent cCustomers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

2.1.2 Such extension does not exceed a total construction cost of \$25,000.

2.2 FREE EXTENSIONS

Such extension shall be free to the cCustomer where the conditions specified in Section 2.1 herein are met and the estimated annual revenue multiplied by two (2) based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable Customer-customer contributions.

2.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 2.1, above, and which exceed the free limits specified in Section 2.2, Company may extend its facilities up to a cost limitation of \$25,000, provided the cCustomer or cCustomers will sign an extension agreement and advance a sufficient portion of the construction cost so that the remainder satisfies the requirements of Section 2.2. Advances are subject to refund as specified in Section 5.

3. ECONOMIC FEASIBILITY BASIS

3.1 GENERAL POLICY - Economic feasibility basis Extensions may be made on the basis of economic feasibility only if all of the following conditions exist:

3.1.1 The aApplicant is or will be a permanent cCustomer or group of permanent cCustomers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

3.1.2 The total construction cost exceeds \$25,000 except for extensions specified in Sections 4.4 or 7.7.



SCHEDULE 3 CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

3.2 FREE EXTENSIONS

Such extensions shall be free to the cCustomer where the conditions specified in Section 3.1 are met and the extension is determined to be economically feasible. "Economic feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the cCustomer.

3.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 3.1, above, Company, after special study and at its option, may extend its facilities to cCustomers whose use does not satisfy the definition of economic feasibility as specified in Section 3.2, provided such cCustomers sign an extension agreement and advance as much of the construction cost and/or agree to pay such higher special rate (facilities charge) as is required to make the extension economically feasible. Advances are subject to refund as specified in Section 5.

4. OTHER CONDITIONS

4.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost, which may include a portion of the shared backbone cost from designated irrigation substations, less the first \$500 of construction or one slack span for Customers owning their own transformers. Advances are subject to refund as specified in Section 5.2. Non-agricultural irrigation pumping will be extended as specified in Section 2 or 3.

4.2 TEMPORARY CUSTOMERS

4.2.1 — Where a temporary meter or construction is required to provide service to the cCustomer, then the cCustomer, in advance of installation or construction, shall make a non-refundable contribution equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain its Company property.

4.2.2 — Contributions for temporary service are nonrefundable.

4.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the cCustomer's residence or operation service is doubtful, the cCustomer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 5.3.



SCHEDULE 3 CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

4.4 REAL ESTATE DEVELOPMENT

Extensions of electric facilities within real estate developments including residential sub-divisions, industrial parks, mobile home parks, apartment complexes, planned area developments, etc., may be made in advance of application for service by permanent customers, as specified in Section 3. Anticipated revenue for Residential Real Estate extensions under the Revenue Basis or Economic Feasibility Basis shall not be differentiated as between all electric or dual energy services shall be calculated from information provided by the developer.

4.4.1 MOBILE HOME PARKS - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the utility as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations.

4.4.2 RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS AND OTHER MULTI UNIT RESIDENTIAL BUILDINGS - Company shall refuse service to all new construction and/or expansion of apartment complexes and condominiums unless the construction and/or expansion is individually metered by the utility as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations. Master metering will only be allowed for buildings utilizing centralized heating, ventilation and/or air conditioning system where the contractor can provide an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations.

4.5 SEASONAL CUSTOMERS

Extensions of electric facilities to Customer's premises which will be continuously occupied less than 9 months out of each 12 month period may be made only on the basis specified in 2. or 3.

5. REFUNDS

5.1 FOOTAGE, REVENUE, AND ECONOMIC FEASIBILITY BASIS REFUNDS

5.1.1 Customer advances of over \$50.00 are subject to full or partial refund, provided that a survey based on conditions of the extension, not including laterals or extensions from the extension being surveyed as specified in Section 5.1.2 existing at the time of survey, results in an advance lower than the amount actually advanced. Except as provided for in Section 5.3, such surveys shall not be made for customers extended to under the basis specified in Section 4.1, 4.2, or 4.3. A survey will be conducted by Company five (5) years after signing the extension agreement under the extension policy in force at the time of the extension and will be made five (5) years after signing the extension agreement. Upon request, the customer will be entitled to intermediate surveys within the five (5) year period after the end of six (6) months following the date of signing the extension agreement and subsequent surveys at intervals of not less than one (1) year thereafter. Company will refund the difference between the amount advanced and the amount that would have been advanced had the advance been calculated at the time of survey. In no event shall the amount of any refund exceed the amount originally advanced.



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

5.1.2 Laterals or extensions from an extension being surveyed shall not be considered in the survey when the lateral or extension was extended on the basis "extensions over the free limits" of ~~Sections 2.2, or 3.2 herein, or is over 300 feet in length or is not connected~~ directly to the extension being surveyed. In real estate developments extended to under the basis specified in Section 4.4, the survey may include laterals and extensions to serve permanent customers located within the real estate development described in the extension agreement for the extension being surveyed.

5.1.3 In lieu of surveys, Company will determine the refund based on the number of permanent connections to the extension for residential real estate development. In such event, Company shall specify in the extension agreement the amount of refund per permanent ~~c~~Customer connection.

5.2 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

~~5.2.1~~ Customer advances of over \$50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

~~5.2.2~~ Customer advances on irrigation extensions over one (1) mile in length will be entitled to an additional refund in the event Company extends service to another irrigation Customer (hereinafter called "new applicant") from such extension. Computations for the refund, as specified in the extension agreement, shall be based on the advance applicable to common facilities used to serve Customer and new applicant or applicants and the number of new applicants. The amount of any refund to Customer shall be collected as a portion of the advance from new applicant. For the purpose of determining refunds to the original Customer, no more than one (1) new applicant per whole mile of original extension will be considered.

5.3 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances of over \$50.00 are subject to full or partial refund pursuant to surveys based on the Revenue or Economic Feasibility Basis as specified in Section 5.1.1. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the cCustomer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.4. GENERAL REFUND CONDITIONS

5.4.1 Customer advances of \$50.00 or less are not subject to refund.

5.4.2 No refund will be made to any ~~c~~Customer for an amount more than the unrefunded balance of the ~~c~~Customer's advance.



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

- 5.4.3 Any unrefunded balance of the cCustomer's advance shall become nonrefundable five (5) years from the date of Company's receipt of the advance.
- 5.4.4 Company reserves the right to withhold refunds to any cCustomer whose account is delinquent and apply these refund amounts to past due bills.

6. UNDERGROUND CONSTRUCTION

- 6.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

- 6.1.1 The extension meets normal overhead feasibility requirements as specified in Sections 1, 2, 3, or 4.
- 6.1.2 The cCustomer or developer provides all earthwork including, but not limited to, trench, boring or punching, conduits, backfill, compaction, and surface restoration in accordance with Company specifications.

(Company may provide all earthwork and Customer or developer will make a nonrefundable contribution equal to the cost of such work provided by Company.)

- ~~6.1.3 If armored cable or special cable covering is required, Customer or developer will make a nonrefundable contribution equal to the additional cost of such cable or covering.~~

- 6.2 THREE-PHASE UNDERGROUND CONSTRUCTION - Where it is determined that three phase is required to serve the cCustomer, Company may install three-phase facilities if the conditions specified in Section 6.1 are met, and the cCustomer provides the following:

- 6.2.1 A nonrefundable contribution per primary circuit foot equal to the estimated difference in cost between overhead and underground facilities. Installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications. In lieu of providing conduits, the customer may provide a nonrefundable contribution equal to the estimated difference in cost between overhead and underground facilities.
- 6.2.2 A nonrefundable contribution for excess service footage required by the cCustomer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.
- 6.2.3 Transformer pad and secondary conduits in accordance with Company specifications. (Company may provide pad and conduits, and the cCustomer or developer will make a non-refundable contribution equal to the cost of such work provided by Company.)



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

6.3 NETWORK AREA

In that portion of Company's service area where the standard service is 277/480 volts from a designated underground network system, Customers who qualify for network service may be supplied standard underground service without extra charge; however, the conditions specified in 6.1 must be met and Customer will be required to make a nonrefundable contribution equal to the cost of the transformer vault where it is used primarily for Customer's benefit.

7. GENERAL CONDITIONS

7.1 VOLTAGE

The extension must will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located.

7.2 THREE PHASE

Extensions for ~~3three~~ phase service can be made under this extension policy where the cCustomer has installed major ~~three3~~ phase equipment. Equipment Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total HP-horsepower of all connected ~~3three~~ phase motors exceeds 12 HP or total load exceeding 100 KVA-kVa demand shall qualify for ~~3three~~ phase. If the estimated load is less than the above HP-horsepower or connected KVA-kVa specifications is installed, Company may, at its option, and when requested by the cCustomer, serve ~~3three~~ phase and require a nonrefundable contribution equal to the difference in cost between ~~4~~ single phase and ~~3three~~ phase construction, but in no case less than \$100.

7.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the cCustomer or developer, or other property required for the extension, shall be furnished in Company's name by the cCustomer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

7.4 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the cCustomer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by Customer or developer.

7.5 OWNERSHIP

Except for cCustomer-owned facilities, all construction, including that for which cCustomers have made advances and/or contributions, will be owned, operated and maintained by Company.



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

7.6 MEASUREMENT AND LOCATION

- 7.6.1 Measurement must be along the proposed route of construction.
- 7.6.2 Construction ~~is to~~ will be on public streets, roadways, highways, or easements acceptable to Company.
- 7.6.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

7.7 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or ~~when in case Customer's requirements estimated load will exceed 2,000 kw 3,000 kW~~, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contact arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

7.8 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way non-standard, as determined by Company, or if unusual obstructions are encountered, ~~the cCustomer~~ will make a non-refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

~~Company maintains current construction standards and endeavors to keep abreast of all modern methods and techniques of construction.~~

7.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided ~~the cCustomer~~ makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

7.10 RELOCATIONS AND/OR CONVERSIONS

- 7.10.1 Company will relocate or convert its facilities for ~~the cCustomer's~~ convenience or aesthetics, providing ~~the cCustomer~~ makes a nonrefundable contribution equal to the total cost of relocation or conversion.
- 7.10.2 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for ~~the cCustomer's~~ convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine ~~the cCustomer's~~ advance on the basis specified in Section 2. or 3.



SCHEDULE 3 CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

7.11 CHANGING OF MASTER METER TO INDIVIDUAL METER

Company will convert its facilities from master metered system to a permanent individually metered system at the cCustomer's request provided the cCustomer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on basis specified in Section 2- or 3.

7.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the cCustomer's added load or change in service requirements on the basis specified in Sections 2- or 3.

7.13 DESIGN DEPOSIT

Any applicant requesting Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction; otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the cCustomer for a line extension upon request.

7.14 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

7.1415 SETTLEMENT OF DISPUTES

Any dispute between the cCustomer or prospective cCustomer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof, for determination.

7.1516 INTEREST

All advances made by the cCustomer to Company in aid of construction shall be non-interest bearing.



SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

7.16 EXTENSION AGREEMENTS

All line extensions requiring payment by the cCustomer shall be in writing and signed by both the cCustomer and Company.

7.17 ADDITIONAL PRIMARY FEED

Company will provide an additional primary (alternate) feed as requested by the customer provided the customer pays the added cost for the additional feed as a nonrefundable contribution in aid of construction and pays the applicable rate for the additional feed requested.



SCHEDULE 4

**TOTALIZED METERING OF MULTIPLE
SERVICE ENTRANCE SECTIONS AT A SINGLE SITE
FOR STANDARD OFFER AND DIRECT ACCESS SERVICE**

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

- A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 7 are all satisfied.
1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1); and
 2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and
 3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and
 4. For Standard Offer customers, totalized metering must be accomplished by a physical wire interconnection of metering information with the customer providing conduit between the SES'; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and
 5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and
 6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer owned generation; and
 7. Written approval by Company's authorized representative is required before totalized metering may be implemented.
- B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:
1. The customer's total load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and
 2. Company requires that load be split and served from multiple SESs; and
 3. The customer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.



SCHEDULE 4

**TOTALIZED METERING OF MULTIPLE
SERVICE ENTRANCE SECTIONS AT A SINGLE SITE
FOR STANDARD OFFER AND DIRECT ACCESS SERVICE**

C. Remote Totalized Metering will apply when conditions A.1-A.7 are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and
2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and
3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus \$500.00, plus all applicable taxes and adjustments.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.
2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.
3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.



SCHEDULE 4

**TOTALIZED METERING OF MULTIPLE
SERVICE ENTRANCE SECTIONS AT A SINGLE SITE
FOR STANDARD OFFER AND DIRECT ACCESS SERVICE**

Arizona Public Service Company (Company) cCustomers at a single premise site whose load requires multiple points of delivery through multiple service entrance sections (SES's) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single premisesite.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 76 are all satisfied.

1. The cCustomer's facilities must be located on adjacent and contiguous premisesites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single premisesite, as specified in Company's Schedule #1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1); and
2. Power will generally be delivered at no less than 277/480 volt (nominal), three-phase, four wire or 120/240 volt (nominal) single phase three wire; and
3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and
34. For Standard Offer customers, totalized metering must be accomplished by a physical wire interconnection of metering information with the cCustomer providing conduit between the SESs; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule #10, Terms and Conditions for Direct Access; and
45. The cCustomer shall provide vault or transformer space, which meets Company specifications, on the cCustomer's property at no cost to Company; and
56. If the cCustomer operates an electric generation unit on the premise, totalized metering will be permitted when the cCustomer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected cCustomer owned generation; and
67. Written approval by Company's authorized representative is required before totalized metering may be implemented.

B. Adjacent Totalized Metering will apply when conditions A.1-A.67 and the following conditions are met:

1. The cCustomer's total load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and
2. Company requires that load be split and served from multiple SESs; and
3. The cCustomer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the cCustomer's monthly bill for Adjacent Totalized Metering.



SCHEDULE 4

**TOTALIZED METERING OF MULTIPLE
SERVICE ENTRANCE SECTIONS AT A SINGLE SITE
FOR STANDARD OFFER AND DIRECT ACCESS SERVICE**

C. Remote Totalized Metering will apply when conditions A.1-A.67 are met, and multiple SES- SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the cCustomer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and
2. The cCustomer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and
3. The cCustomer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the cCustomer receiving Remote Totalized Metering. However, lower capital investment which results from the cCustomer's contribution, other than the meter costs in C.3 above, shall not be considered.

For cCustomers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus \$500.00, plus all applicable taxes and adjustments. For Standard Offer Customers the surcharge of 1% shall be based on their Standard Offer bill. For Direct Access Customers, the surcharge of 1% shall be based on the otherwise applicable Standard Offer rate (either Rate E-32 or E-34). After October 1, 1999 Remote Totalizing with charge will not be available to any Customers not already receiving such service.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.
2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.
3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.



**SCHEDULE 7
ELECTRIC METER
TESTING AND MAINTENANCE PLAN**

General Plan

This schedule establishes a monitoring plan for electric meters in order to ensure an acceptable degree of performance in the registration of the energy consumption of Arizona Public Service Company (Company) customers. Company will file an annual report with the Arizona Corporation Commission summarizing the results of the performance monitoring plan.

Specific Plan

1. Single-Phase Self Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

- 1.1 Meters shall be separated into groups having common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four (4).

Reference: ANSI C12.1-2001 sections 5.1.4 through 5.1.5.4 or as may be amended by ANSI

- 1.2 Analysis of the test results for each group evaluated shall be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 - 1993 Formulas B-3, Tables A-1, A-2 and B-5. The minimum sample size shall be 100 meters when possible.

2. Single Phase Self Contained Meters - Solid State

Company will monitor performance of these types of meters through the Company Metering and Billing systems.

3. Three Phase Self-Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

Company shall monitor installations with the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

- 3.1 Three-phase meters with surge-proof magnets and without demand registers or pulse initiators: 16 years.
- 3.2 Three phase block-interval demand-register-equipped kWh meters with surge-proof magnets: 12 years.
- 3.3 Three phase lagged-demand meters: 8 years.

4. Three Phase Self-Contained Meters - Solid State

Company will monitor performance for these types of meters through the Company Metering and Billing systems.



**SCHEDULE 7
ELECTRIC METER
TESTING AND MAINTENANCE PLAN**

5. Three Phase Transformer-Rated Meter Installations – Solid State Hybrids and Electro-Mechanical

Company will conduct a periodic testing program whereby three phase transformer-rated meter installations along with their associated equipment shall be inspected and tested for accuracy according to the following schedule:

- 5.1 Installations with 500 to 1,000 kW load: 4 years.
- 5.2 Installations with 1001 kW to 2000 kW load: 2 years.
- 5.3 Installations over 2000 kW load: 1 year.



SCHEDULE 7 ELECTRIC METER TESTING AND MAINTENANCE PLAN

General Plan

This schedule establishes a monitoring plan for electric meters in order to ensure an acceptable degree of performance in the registration of the energy consumption of Arizona Public Service Company (Company) customers. To inspect and test electric meters to ensure safe, accurate, and dependable electric service to all customers. Company will file an annual report with the Arizona Corporation Commission summarizing the results of the performance monitoring plan meter maintenance and testing program for that year.

Specific Plan

1. Single-Phase Self Contained Single Phase KWH Meters, Single Phase Block Interval Demand Register Equipped KWH Meters, and Single Phase Lagged Demand Meters 1/ - Non-Solid State Hybrids and Electro-Mechanical

1.1 Meters shall be separated into groups having common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four (4).

Reference: ANSI C12.1-2001 sections 5.1.4 through 5.1.5.4 or as may be amended by ANSI

1.2 Analysis of the test results for each group evaluated shall be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 - 1993 Formulas B-3, Tables A-1, A-2 and B-5. The minimum sample size shall be 100 meters when possible.

Company will conduct a continuous selective meter testing program. Meters shall be separated into homogeneous groups having common physical attributes and the Full Load test point for meters which have been in service shall be evaluated using statistical formulas as follows. The minimum sample shall be 100 meters, and the evaluation shall be made annually.

Each meter group being evaluated shall meet the following criteria:

\bar{X} (Bar X) — average error in percent of the sample of meters and is the arithmetic mean of the sample accuracies

$$\bar{X} = \frac{\sum X}{N}$$

σ (Sigma) — standard deviation of the normal distribution curve, and is a measure of the dispersion of the as found
— test data about the mean

$$\sigma = \sqrt{\frac{\sum (X)^2}{N} - \bar{X}^2}$$

Where: $\sum (X)^2$ — summation of the products of numbers of meters and point by point squared accuracies



SCHEDULE 7 ELECTRIC METER TESTING AND MAINTENANCE PLAN

N — size of sample

X — individual values of sample accuracies

The above calculated values shall be substituted in the following equations to determine if the meter group being evaluated meets the following criteria statement: 98% of all meters in each homogeneous group are within + 3% of accurate, with a 95% confidence level:

$$\text{High side (maximum)} = \bar{X} + 2\sigma_{\bar{X}} + 2.33\sigma_{\sigma} + 2\sigma_{\sigma}$$

$$\text{Low side (minimum)} = \bar{X} - 2\sigma_{\bar{X}} - 2.33\sigma_{\sigma} - 2\sigma_{\sigma}$$

Where: $\sigma_{\bar{X}}$ — possible error in \bar{X}

$$\sigma_{\bar{X}} = \frac{\sigma}{\sqrt{N}}$$

σ_{σ} — possible error in σ

$$\sigma_{\sigma} = \frac{\sigma}{\sqrt{2N}}$$

2. Single Phase Self Contained Meters – Solid State

Company will monitor performance of these types of meters through the Company Metering and Billing systems.

3. All Other Three Phase Self-Contained Meters ~~2/-~~ Non-Solid State Hybrids and Electro-Mechanical

Company shall monitor installations with the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

Shall be tested for accuracy and recalibrated according to the following test schedule.

- 3.1. Three-phase mMeters with surge-proof magnets and without demand registers or pulse initiators: 16 years.
- 3.2. Three phase block-interval demand-register-equipped ~~KWH~~ kWh meters with surge-proof magnets: 12 years.
- 3.3. Three phase lagged-demand meters: 8 years.

4. Three Phase Self-Contained Meters – Solid State

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Phoenix, Arizona
Filed by: Alan Propper
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SCHEDULE 7

ELECTRIC METER TESTING AND MAINTENANCE PLAN

Company will monitor performance for these types of meters through the Company Metering and Billing systems.

5. All-Three Phase Transformer-Rated Meters ~~2/~~ Installations – Solid State Hybrids and Electro-Mechanical

Company will conduct a periodic testing program whereby three phase transformer-rated meter installations along with their associated equipment shall be inspected and tested for accuracy according to the following schedule:

Shall be tested for accuracy and recalibrated according to the following test schedule.

5.1. Installations with ~~With less than 500~~ 500 to 1,000 kKW load: 4 years.

5.2. Installations w~~With~~ 500-1001 kKW to 2000 kKW load: 2 years.

5.3. Installations ~~With~~ over 2000 kKW load: 1 year.

~~1/ See ANSI Standard C12-1975, Paragraph 8.1.8.6~~

~~2/ See ANSI Standard C12-1975, Paragraphs 8.1.8.4 and 8.2.3.1~~



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

The following terms and conditions and any changes authorized by law will apply to Arizona Public Service Company (Company), Energy Service Providers (ESPs), and their agents that participate in Direct Access under the Arizona Corporation Commission's (ACC) rules for retail electric competition (A.A.C. R14-2-1601, *et seq.*, referred to herein as the "Rules"). "Direct Access customer" refers to any Company retail customer electing to procure its electricity and any other ACC authorized Competitive Services directly from ESPs as defined in the Rules.

Customer Selections

All Company retail customers shall obtain service under one of two options:

1. Standard Offer Service. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, at regulated rates authorized by the ACC. Any customer who is eligible for Direct Access who does not elect to procure Competitive Services shall remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access.
2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have Interval Metering, as specified in Section 3.6.1. Pursuant to the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have Company provide those services (when permitted by the Rules) as specified within.

1. General Terms

- 1.1. Definitions. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.
 - 1.1.1. Customer - Unless otherwise stated, all references to Customer in this agreement refer to Company customers who are eligible for and have elected Direct Access.
 - 1.1.2. Service Account - Unless otherwise stated, all references to "Service Account" in this agreement shall refer to an installed service, identified by a Universal Node Identifier (UNI).
 - 1.1.3. Local Arizona Time - All time references in this Schedule are in Local Arizona Time, which is Mountain Standard Time (MST).

2. General Obligations of Company

2.1. Non-Discrimination

- 2.1.1. Company shall discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, Company shall not:



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 2.1.1.1. Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of Company services than other, unaffiliated services providers as a result of affiliation with Company; or
- 2.1.1.2. Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of Company services.

2.2. Transmission and Distribution Service

Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

3. General Obligations of ESPs

3.1. Timeliness, Due Diligence and Security Requirements

- 3.1.1. ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs shall make all payments owed to Company in a timely manner.
- 3.1.2. ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and Company tariffs and schedules.

3.2. Arrangements with ESP Customers

ESPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access. Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3. Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4. Company Not Liable for ESP Services

To the extent the customer elects to procure services from an ESP, Company has no obligations to the customer with respect to the services provided by the ESP.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

3.5. Load Aggregation for Procuring Electric Generation/Split Loads

- 3.5.1. ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute Company charges or for tariff applicability.
- 3.5.2. Customers requesting Direct Access Services may not partition the electric loads of a Service Account among electric service options or providers. The entire load of a Service Account must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

3.6. Interval Metering

- 3.6.1. "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand in excess of 20 kW one or more times or annual usage of 100,000 kWh or more. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less or annual usage of less than 100,000 kWh.
- 3.6.2. Company shall determine if Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers.

3.7. Meter Data Requirements

Minimum meter data requirements consist of data required to bill Company distribution tariffs and determine transmission settlement. Company shall have access to meter data necessary for regulatory purposes or rate-setting purposes pursuant to mutually agreed upon terms with the ESP for such data access.

3.8. Statistical Load Profiles

Pursuant to R14-2-1604(B)(3) Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9. Fees and Other Charges

Direct Access customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

3.10. Liability In Connection With ESP Services

- 3.10.1. "Damages" shall include all losses, harm, costs and detriment, both direct and indirect, and consequential, suffered by Customer or third parties.
- 3.10.2. Company shall not be liable for any damages caused by Company conduct in compliance with, or as permitted by, Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in Company Schedule #1.
- 3.10.3. Company shall not be liable for any damages caused to Customer by any ESP, including failure to comply with Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.
- 3.10.4. Company shall not be liable for any damages caused by the ESP's failure to perform any commitment to Customer.
- 3.10.5. An ESP is not a Company agent for any purpose. Company shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.
- 3.10.6. Under no circumstances shall Company be liable to Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to customers under Company's schedules and tariffs and applicable laws and regulations.

4. Customer Inquiries and Data Accessibility

- 4.1 Customer Inquiries – For customers requesting information on Direct Access, Company shall make available the following information:
 - 4.1.1 Materials to consumers about competition and consumer choices.
 - 4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within Company's service territory. Company will provide the list maintained by the ACC, but Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by Company.
- 4.2 Access to Customer Usage Data. For Company customers on Standard Offer Service, Company shall provide customer specific usage data to ESP or to Customer, subject to the following provisions:
 - 4.2.1. ESPs may request Customer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. Company may charge for customer usage data.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 4.2.2. Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.
- 4.3 Customer Inquires Concerning Billing Related Issues
 - 4.3.1 Customer inquiries concerning Company charges or services shall be directed to Company.
 - 4.3.2 Customer inquiries concerning ESP charges or services shall be directed to the ESP.
- 4.4 Customer Inquiries Related to Emergency Situations and Outages
 - 4.4.1. Company shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to Company for resolution. ESPs performing consolidated billing must show Company's emergency telephone number on their bills.
 - 4.4.2. Company may shed or curtail customer load as provided by its ACC-approved tariffs and schedules, or by other ACC rules and regulations.
- 5. ESP Service Establishment
 - 5.1. Before the ESP or its agents can offer Direct Access services in Company distribution service territory they must meet the applicable provisions as listed:
 - 5.1.1. All ESPs must obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services in Company's distribution service territory.
 - 5.1.2. All ESPs must register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services in Company's distribution service territory.
 - 5.1.3. Load Serving ESPs must satisfy creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.
 - 5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.
 - 5.1.5. All ESPs must satisfy any applicable ACC electronic data exchange requirements including:
 - 5.1.5.1. The ESP and/or its designated agents must complete to Company's satisfaction all necessary electronic interfaces between the ESP and Company to exchange DASRs and general communications.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 5.1.5.2. The ESP or its agent must complete to Company's satisfaction all electronic interfaces between the ESP and Company to exchange meter reading and usage data. This includes communication to and from the Meter Reading Service Provider's (MRSP) server for sharing of meter reading and usage data.
- 5.1.5.3. The ESP must have the capability to electronically exchange data with Company. Alternative arrangements may be acceptable at Company's option.
- 5.1.5.4. The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when providing meter reading services. Alternative arrangements may be allowed at Company's option.
- 5.1.6. For Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing is required. Both parties must demonstrate the ability to perform data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access customers. Dual Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.
- 5.1.7. Compliance testing will be required for a Load Serving ESP or its MRSP when providing meter reading services to ensure that meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing.
6. Direct Access Service Request (DASR)
- 6.1 A DASR is submitted pursuant to the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the customer.
- 6.2 ESPs shall have a CC&N from the ACC; shall have entered into an ESP Service Acquisition Agreement with Company, if required, and shall have successfully completed data exchange compliance testing before submitting DASRs.
- 6.3 The customer's authorized ESP must submit a completed DASR to Company before Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

- 6.4. A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to Company. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing DASRs are thereby representing that they have their customer's authorization for such transaction.
- 6.5. Company requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the Company's web site (<http://esp.apsc.com>).
- 6.6. DASRs will be handled on a first-come, first-served basis. Each request shall be time and date stamped when received by Company.
- 6.7. Once the DASR is submitted, the following timeframes will apply:
- 6.7.1. Company will respond to RQ, TS, CL and UC DASRs within two (2) working days of the time and date stamp. Company will exercise best efforts (no later than five (5) working days) to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 and will be confirmed in the response to the ESP and the former ESP if applicable. If a DASR is rejected, Company shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or a mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.
- 6.7.2. When a customer requests electric services to be disconnected, the ESP is responsible for submitting a PD DASR to Company on behalf of the customer, regardless of the Meter Service Provider (MSP).
- 6.7.2.1. When Company is acting as the MSP, Company shall perform the physical disconnect of the service. The PD DASR must be received by Company at least three (3) working days prior to the requested disconnect date. Company will acknowledge the PD DASR status within two (2) working days of the time and date stamp.
- 6.7.2.2. When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP shall notify Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the server within three (3) working days following the disconnection.
- 6.8. DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates shall be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").
- 6.10. If more than one (1) RQ DAsR is received for a service delivery point within a Customer's billing cycle, only the first valid DAsR received shall be processed in that period. All subsequent DASRs shall be rejected.
- 6.11. Upon acceptance of an RQ DAsR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.
- 6.12. Customers returning to Company Standard Offer service must contact their ESP. The ESP shall be responsible for submitting the DAsR on behalf of the customer.
- 6.13. ESPs requesting to return a Direct Access customer to Company Standard Offer service shall submit a TS DAsR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.
- 6.14. Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access Service.
- 6.15. Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.
- 6.16. A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the necessary information that will enable its ESP to submit a DAsR. The same timing requirements apply as set forth in Section 6.8 and 6.9.
- 6.17. Billing and metering option changes are requested through a UC DAsR and cannot be changed more than once per billing cycle.
- 6.18. Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer shall not make Company liable to the ESP or third-parties for the customer's disconnection.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

- 7.1 ESPs may select among the following billing options:

- 7.1.1 COMPANY UDC CONSOLIDATED BILLING
- 7.1.2 ESP CONSOLIDATED BILLING
- 7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

- 7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

- 7.2.2.1 Company shall bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company shall comply with A.A.C. R14-2-1612.

- 7.2.2.2 Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

- 7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP shall receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

- 7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

- 7.2.3.2 The ESP shall submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule, and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

7.2.4 Timing Requirements

- 7.2.4.1. Bills under this option will be rendered once a month. Nothing contained in this Schedule shall limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.
- 7.2.4.2. Except as provided in Section 7.2.4.1, Company shall require that all ESP and Company charges be based on the same billing period data.
- 7.2.4.3. ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that Company charges were previously billed.
- 7.2.4.4. ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5. Restrictions

Company UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3. ESP CONSOLIDATED BILLING

- 7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

7.3.2 Company Obligations:

- 7.3.2.1 Company shall calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.
- 7.3.2.2 Company shall provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.
- 7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP shall include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations:

- 7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.
- 7.3.3.2 The ESP bill shall include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP shall comply with A.A.C. R14-2-1612.
- 7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.
- 7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company shall continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) shall resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company shall be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company shall transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP shall apply the charges to Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP shall be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company shall remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP shall pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments shall be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

- 7.8.1.3 ACC rules shall apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account shall be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP shall be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company shall not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

- 7.9.1 Company shall notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges prior to disconnecting electric service to the Customer. Company shall further notify the ESP at the time Customer has been disconnected. To the extent authorized by the ACC, a service charge shall be imposed on Customer if a field call is performed to disconnect electric service.

- 7.9.2 Company shall reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company shall notify the ESP of a Customer's reconnection.

- 7.9.3 Company shall not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10. Involuntary Service Changes

- 7.10.1. A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

- 7.10.1.1. The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.
- 7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.
- 7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.
- 7.10.1.5 The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2. Change of Service Election in Exigent Circumstances

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company shall provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by Company. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to Customer other than as provided in Section 4.4.2.

7.10.3. Change in Service Election Absent Exigent Circumstances

- 7.10.3.1. In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2) or involve an ESP's unauthorized energy use, Company shall notify the ESP and the ACC of such finding in writing stating the following:



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 7.10.3.1.1. The nature of the alleged failure;
- 7.10.3.1.2. The actions necessary to remedy the failure;
- 7.10.3.1.3. The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2. The ESP shall have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4. Termination of ESP Consolidated Billing

7.10.4.1. Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1. The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

- 7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.
- 7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.
- 7.10.4.1.1.3 The ESP files for bankruptcy.
- 7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.
- 7.10.4.1.1.5 The ESP admits insolvency.
- 7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.
- 7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.
- 7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 7.10.4.1.2. If the ESP fails to pay Company (or dispute payment pursuant to the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.
- 7.10.4.1.3. If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.
- 7.10.4.2. Upon termination of ESP Consolidated Billing pursuant to Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.
- 7.10.4.3. Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.4 and 7.11, and payment to Company of all costs associated with changing ESP customers' billing elections to and from dual billing.
- 7.10.4.4. In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.
- 7.10.5. Termination of Company UDC Consolidated Billing
- 7.10.5.1. Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.
- 7.10.5.2. Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.
- 7.10.6. Upon termination of ESP Direct Access services pursuant to Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company shall provide such services, until such time that Customer makes an election.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

7.10.7. Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11. ESP Security Deposits

7.11.1. Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2. The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3. Security deposits required pursuant to Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4. Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to Section 7.11.

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MSRP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for Residential Load-Profiled Customers

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party. If the ESP sub-contracts any of the components of these services to a third party, the ESP shall, for the purposes of this Schedule, remain responsible for the services.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test
ANSI 57.13	Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with Company's meter reading system.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

- 8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.
- 8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh Electro-Mechanical	Trouble	Meter Test
1 Ph kWh Hybrid or Solid State	Routine	Meter Test
1 Ph TOU (all)	Trouble	Meter Test
3 Ph Meters (all)	All	Meter Test
1 Ph or 3 Ph IDR Meters	All	Meter Test

- 8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.
- 8.7.4 Records on meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and Company shall use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.9 Meter Identification

- 8.9.1 The ESP or its agent shall install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.
- 8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

- 8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.
- 8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.
- 8.10.3 The ESP or its agent shall inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.
- 8.10.4 The ESP or its agent shall return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

- 8.11.1 Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements. Company shall perform a preinstallation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC shall coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 Company shall own the CTs, PTs and associated equipment.

8.12.3 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation. Company may optionally provide meter installation pursuant to the Rules.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.14 As part of providing metering services, ESPs or their agents shall:

- 8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.
- 8.14.2 If lock rings are used they shall meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.
- 8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.
- 8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP shall coordinate with Company regarding the return of the meters.
- 8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.
- 8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.
- 8.14.7 Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.
- 8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.
- 8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next schedules read date. MSRP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 8.15.1 Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.
- 8.15.2 Both Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.
- 8.15.3 Meter read data shall include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data shall contain applicable reason codes pursuant to the 867 guidelines.
- 8.15.4 The MRSP shall provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.
- 8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.
- 8.15.6 MRSPs shall read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.
- 8.15.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters.

- 8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.
- 8.16.1.2 Meter read date and time shall be accurate.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.16.1.3 All meter reading data shall be validated with the pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Pursuant to guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data shall be available by 3:00 p.m. Local Arizona Time (MST) on the third working day after the scheduled read date. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP shall be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Prior to performing MRSP services in Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions:

If Company is eligible to perform Direct Access related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.



SCHEDULE 10

TERMS AND CONDITIONS FOR DIRECT ACCESS

- 8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:
- 8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.
 - 8.18.2.2 Company may repair the defect, and the other party shall be responsible for all related expenses.
 - 8.18.2.3 Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.
- 8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to section 7.10.1.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.





SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

The following terms and conditions and any changes authorized by law will apply to APS Arizona Public Service Company (Company), Energy Service Providers (ESPs), ESPs and their agents that participate in Direct Access under the Arizona Corporation's Commission's ("ACC") rules for retail electric competition (A.A.C. R14-2-1601, et seq., referred to herein as the "Rules"). "Direct Access customer" refers to any APS Company retail customer electing to procure its electricity and any other ACC-authorized Competitive Services directly from ESPs as defined in the Rules. ESPs who serve Direct Access customer accounts shall possess a Certificate of Convenience and Necessity, issued by the ACC pursuant to A.A.C. R14-2-1601; enter into an ESP Service Acquisition Agreement with APS and an agreement with an APS-approved and/or Arizona Independent Scheduling Administrator Association ("AISA") approved Scheduling Coordinator; be registered to do business in the State of Arizona; and meet any other applicable certification requirements established by State law and by the appropriate regulatory agencies.

Customer Selections

All APS Company retail electric customers shall obtain electric generation and ACC authorized energy services under one of two options:

1. Standard Offer Service (Bundled Service). With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, on a bundled basis at regulated rates authorized by the ACC. Any customer that has not chosen Direct Access, and who is eligible for Direct Access, who is eligible for Direct Access who does not elect to procure Competitive Services shall remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access. Refer to R14-2-1601 for further definitions.
2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive Services services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have in place Interval Metering, as defined below at no expense to APS, specified in Section 3.6.1. Pursuant to the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have APS the Company provide those services (when permitted by the Rules) as specified within. Meter service options are described in the Sections on Metering Services and Meter Service Options and Obligations in this Schedule #10. Billing options are described in the Sections on Billing Service Options and Obligations in this Schedule #10 and the ESP Service Acquisition Agreement.

1. General Terms

- 1.1. Definitions. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

- 1.1.1. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

~~1.1.2.1.1.1.~~ Customer - Unless otherwise stated, all references to ~~"customer"~~Customer in this agreement refer to APS Company customers who are eligible for and have elected Direct Access.

1.1.32. Service Account - Unless otherwise stated, all references to ~~"Service Account"~~Service Account in this agreement shall refer to an installed service, identified by a Universal Node Identifier (UNI).

~~1.1.4.~~ First Meter Read Date - Unless otherwise stated, all references to ~~"First Meter Read Date"~~First Meter Read Date shall refer to the first working day that meter reads can be obtained for a billing cycle. APS will publish the meter read schedule yearly, by month, subject to change.

~~1.1.5.~~ Last Meter Read/First Bill Date - Unless otherwise stated, all references to ~~"Last Meter Read Date/First Bill Date"~~Last Meter Read/First Bill Date shall refer to a pre-established working day defined each month for the purpose of producing customer bills. The Last Meter Read/First Bill Date is the first day of the APS bill processing window. The Last Meter Read/First Bill Date will always be at least three (3) days after the First Meter Read Date. APS will publish the meter read schedule yearly, by month, subject to change.

1.1.63. Local Arizona Time - All time references in this Schedule # 10 are in Local Arizona Time, which is Mountain Standard Time (MST). Arizona does not observe Daylight Savings Time.

2. General Obligations of APS Company

2.1. Non-Discrimination

2.1.1. APS Company shall discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, APS Company shall not:

2.1.1.1. Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of APS Company services than other, unaffiliated services providers as a result of affiliation with APS Company; or

2.1.1.2. Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of APS Company services.

2.2. Transmission and Distribution Service

~~2.2.1.~~ Subject to State law and the terms of the ACC's Rules and Regulations, this Schedule # 10, the ESP Service Acquisition Agreement, applicable tariffs and applicable ACC and FERC rules, and provided the ESP and customer likewise comply therewith, APS Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers, under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

2.3. Competitive Transition Charges (CTC)

~~2.3.1. Competitive Transition Charges are a means of recovering Stranded Costs from customers who elect Direct Access Service. As a condition for receiving Direct Access Service, these customers will be responsible to APS for all CTC charges (or any other means of recovering stranded costs) as authorized by the Rules and as may be subsequently approved by the ACC.~~

2.4. System Benefit Charges (SBC)

~~2.4.1. System Benefits Charges are those charges approved by the Commission for recovery of low-income, demand-side management, environmental, renewable, nuclear fuel disposal costs and nuclear power plant decommissioning costs and other approved costs from customers that elect Direct Access Service. As a condition for receiving Direct Access Service, these customers will be responsible to pay all System Benefit Charges authorized by the Rules in A.A.C. R14-2-1608 and as may be subsequently approved by the ACC.~~

3. General Obligations of ESPs

3.1. Timeliness, Due Diligence and Security Requirements

3.1.1. ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs shall make all payments owed to APS Company in a timely manner (pursuant to the ACC's requirements, the Rules, the ESP Service Acquisition Agreement the ESP enters into with APS, and APS' tariffs and schedules) and subject to applicable payment dispute provisions described below.

3.1.2. ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and APS' Company tariffs and schedules.

3.2. Arrangements with ESP Customers

~~3.2.1. ESPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access consistent with all applicable laws, ACC requirements, the Rules and this Schedule # 10. APS Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.~~

3.3. Responsibility for Electric Purchases

~~3.3.1. ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").~~

3.4. APS Company Not Liable for ESP Services

~~3.4.1. To the extent the customer elects to take other procure services from an ESP, APS Company has no obligations to the customer with respect to the services provided by the ESP.~~



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

3.5. Load Aggregation for Procuring Electric Generation/Split Loads

- 3.5.1. ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute APS Company charges or for tariff applicability.
- 3.5.2. Customers requesting Direct Access Services may not partition the electric loads of a Sservice Account among electric service options or providers. The entire load of a Sservice Account must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

3.6. Interval Metering

- 3.6.1. "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and have reach a maximum single premise-site maximum demands in excess of 20 kW one or more times or annual usage of 100,000 kWh or more annually. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less demands of 20 kW or annual usage of 100,000 kWh annually or less or more.
- 3.6.2. ~~For new customers without prior demand data, APS shall estimate the demand at the time the customer establishes a distribution service account with APS. APS Company shall determine, based on its estimates of the customer's demand, whether if the Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers. With the customer's written consent, APS shall provide the customer's ESP with the data upon which the demand estimate was made.~~

3.7. Metering Data Requirements

~~3.7.1. Minimum meter data requirements consist of data required to bill APS Company distribution tariffs and determine transmission settlement. APS Company shall have access to meter data necessary for regulatory purposes or rate-setting purposes pursuant to mutually agreed upon terms with the ESP for such data access.~~

3.8. Statistical Load Profiles

~~3.8.1. Pursuant to R14-2-1604(B)(3) and R14-2-1603(D)(7) APS Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.~~



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

3.9 Fees and Other Charges

~~3.9.1.~~ Direct Access customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and APS Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and APS Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10. Liability In Connection With ESP Services

3.10.1. ~~In this section, "damages"~~ "Damages" shall include all losses, harm, costs and detriment, both direct, ~~and indirect, and consequential,~~ suffered by the ~~Customer~~ or third parties.

3.10.2. APS Company shall not be liable for any damages caused by APS' Company conduct in compliance with, or as permitted by, APS' Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in APS' Company's Schedule #1.

3.10.3. APS Company shall not be liable for any damages caused to the ~~Customer~~ by any ESP, including failure to comply with APS' Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4. APS Company shall not be liable for any damages caused by the ESP's failure to perform any commitment to the ~~Customer~~, including.

3.10.5. An ESP is not an APSa Company agent for any purpose. APS Company shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances shall APS Company be liable to the ~~Customer~~, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to customers under APS' Company's schedules and tariffs and applicable laws and regulations.

4. Customer Inquiries and Data Accessibility

4.1 Customer Inquiries – For customers requesting information on Direct Access, APS Company shall make available the following information:

4.1.1 ~~Notification and informational materials~~ Materials to consumers about competition and consumer choices.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within APS' Company's service territory. APS Company will provide the list maintained by the ACC, but APS Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by APSCompany.
- 4.2. Access to Customer Usage Data. -- For APS Company customers on Standard Offer Service, APS Company shall provide customer specific usage data to ESP's that have an ESP Service Acquisition Agreement in place with APS, or to the Customer, subject to the following provisions:
- 4.2.1. ESPs may request Customer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to APS Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. APS Company may charge for customer usage data at rates approved by the ACC.
- 4.2.2. APS Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.
- 4.3 Customer Inquires Concerning Billing Related Issues
- 4.3.1 Customer inquiries concerning APS Company charges or services shall be directed to APSCompany.
- 4.3.2 Customer inquiries concerning ESP charges or services shall be directed to the ESP.
- 4.4. Customer Inquiries Related to Emergency Situations and Outages
- 4.4.1. APS Company shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to APS' Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to APS Company for resolution. ESPs performing consolidated billing must show APS' Company's emergency telephone number on their bills for use in emergencies.
- 4.4.2. APS Company may shed or curtail customer load as provided by its ACC approved tariffs and schedules, or by other ACC rules and regulations.
5. ESP Service Establishment
- 5.1. ~~An ESP, providing competitive generation, shall satisfy the following requirements before the ESP or its agents can offer Direct Access services in APS' Company distribution service territory they must meet the applicable provisions as listed:~~
- ~~5.1.1. Enter into an ESP Service Acquisition Agreement with APS.~~



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 5.1.31. All ESPs must Obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services to Direct Access customers within APS' Company's distribution service territory.
- 5.1.32. All ESPs must Register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services to Direct Access customers in APS' Company's distribution service territory.
- 5.1.43. Load Serving ESPs must satisfy APS' creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP will offer chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.
- 5.1.4. Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.
- 5.1.5. All ESPs must satisfy any applicable ACC electronic data exchange requirements including:
- 5.1.5.1. The ESP and/or its designated agents must successfully complete to Company's satisfaction all necessary electronic interfaces between the ESP and APS Company to exchange DASRs and general communications.
- 5.1.5.2. The ESP or its agent must successfully complete to Company's satisfaction all electronic interfaces between the ESP and APS Company to exchange meter reading and usage data. This will include communication to and from the Meter Reading Service Provider's (MRSP) servers for sharing of meter reading and usage data.
- 5.1.5.3. The ESP must have the capability to electronically exchange data with APS electronically Company. Alternative arrangements may be acceptable if mutual agreement is reached between APS and the ESP at Company's option.
- 5.1.5.4. The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when providing meter reading services. APS will require the ESP and its agents to exchange data with APS using Electronic Data Interchange (EDI), and enter into appropriate agreements as part of the ESP Service Acquisition Agreement, if the ESP or its agents will be offering APS UDC Consolidated Billing, ESP Consolidated Billing, or metering or meter reading services. Alternative arrangements may be allowed at Company's option if mutual agreement is reached between APS and the ESP.



SCHEDULE 10

TERMS AND CONDITIONS FOR DIRECT ACCESS

- 5.1.6. For the APS Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing for EDI transactions will be required. Both parties must demonstrate the ability to perform the EDI data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access customers. Dual APS Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.
- 5.1.7. Compliance testing will be required for Meter Reading Service Providers (MRSP) a Load Serving ESP or its MRSP when providing meter reading services to ensure that billing can be completed meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing applicable. APS reserves the right to charge the ESP for obtaining or estimating reads at ACC approved rates until such time as the MRSP has completed successful compliance testing as outlined in Section 8.16.3 of this Schedule # 10.
6. Direct Access Service Request (DASR)
- 6.1 A Direct Access Service Request ("DASR") is submitted pursuant to the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the customer.
- 6.2 ESPs shall have a CC&N from the ACC; shall have entered into an ESP Service Acquisition Agreement with APS Company, if required, and shall have successfully completed EDI data exchange compliance testing before submitting DASRs.
- 6.3 The customer's authorized ESP must submit a completed DASR to APS Company before the Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to APS Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.
- 6.4. A separate DASR must be submitted for each service delivery point. Each of the five- (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to APS Company. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, APS Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing RQ DASRs are thereby representing that they have their customer's written authorization for such transaction. ESPs filing all other DASRs are thereby representing that they have their customer's authorization for such transaction.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

- 6.5. ~~APS Company may requires~~ that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the APS Company's web site (<http://esp.apsc.com>).
- 6.6. DASRs will be handled on a first-come, first-served basis. Each request shall be time and date stamped when received by APSCcompany.
- 6.7. Once the DASR is submitted, ~~APS will provide an acknowledgment of its receipt to the ESP or customer within the following timeframes~~ the following timeframes will apply:
- 6.7.1. ~~APS Company will respond to Request (RQ), Termination of Service Agreement (TS), Cancel (CL) and Update/Change (UC) DASRs within two (2) working days of the time and date stamp. APS Company will exercise best efforts, within three (3) working days thereafter (and no later than five (5) working days thereafter), to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 of this Schedule # 10, and will be confirmed in the response to the ESP; and the former ESP if applicable, and through written notification to the customer. If a DASR is rejected, APS Company shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or as mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.~~
- 6.7.2. When a customer requests ~~its~~ electric services to be disconnected, the ESP is responsible for submitting a Physical Disconnect (PD) DASR to APSCcompany on behalf of the customer, regardless of who controls the meter, ~~on behalf of the customer~~ the Meter Service Provider (MSP).
- 6.7.2.1. ~~When the control of the meter resides with APSCcompany is acting as the MSP, it Company shall perform the physical disconnect of the service. The "PD" DASR must be received by APS Company at least three (3) working days prior to the requested disconnect date. APS Company will acknowledge the "PD" DASR status within the two (2) working days of the time and date stamp.~~
- 6.7.2.2. ~~When the control of the meter resides with the ESP When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP shall notify APS Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the MRSP or ESP server within three (3) working days following the disconnection.~~
- 6.8. ~~Pursuant to A.A.C. R14-2-203(D)(4), DASRs for customers that do not require a meter exchange must be received by APS Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date will would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.~~



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 6.9. Accepted DASRs that require a meter exchange will have an effective change date to Direct Access with theas of the meter exchange date. Notification of meter install exchange dates shall be coordinated between the ESPs, MSPs and APS² Company's Meter Activity Coordinator ("MAC").
- 6.10. If more than one (1) RQ DADR is received for a service delivery point within a Customer's billing cycle, only the first valid DADR received shall be processed in that period. All subsequent DASRs shall be rejected.
- 6.11. Upon acceptance of an RQ DADR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date. ESPs filing DASRs will thereby be representing that they have written authorization from the customer to receive the customer usage information.
- 6.12. Customers returning to APS Company Standard Offer service shall follow the same process timing as is used to establish Direct Access service must contact their ESP. The ESP shall be responsible for submitting the DADR on behalf of the customer.
- 6.13. ESPs requesting to return a Direct Access customer to APS Company Standard Offer service shall submit a Termination of Service TS DADR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.
- 6.14. Customers requesting to return to APS² Company Standard Offer service must contact their ESP. The ESP shall be responsible for submitting the appropriate DADR on behalf of the customer are subject to the same timing requirements as used to establish Direct Access Service.
- 6.15. APS Company may assess a charge fee for processing DASRs at a fee approved by the ACC. All ACC-approved charges fees are payable to APS Company within fifteen (15) calendar days after the invoice date. All charges received All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule #1. If an ESP fails to pay these charges fees within thirty (30) days after the due date, APS Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the charges fees due is currently available or until such time as the charges fees are paid. If an ESP is late in paying charges fees, a deposit or an additional deposit may be required from the ESP.
- 6.16. A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact APS Company to establish a Sservice Aaccount. The customer will be provided the necessary information that will enable its ESP to submit a DADR. The same timing requirements apply as set forth in this Section 6.8 and 6.9 of Schedule # 10. Customer eligibility requirements set forth in the ACC Rules will apply during the phase-in period (January 1, 1999 through December 31, 2000).
- 6.17. Billing ~~option~~ and metering option changes are requested through a "UC" DADR and cannot be changed more than once per billing cycle.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

- 6.18. APS Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the customer's responsibility to pay APS Company. APS Company's Schedule # 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. APS Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by APS Company of a delinquent customer shall not make APS Company liable to the ESP or third-parties for the customer's disconnection.
- 6.19. During the phase-in period (January 1, 1999 through December 31, 2000), residential customers will be eligible for Direct Access on a first come, first served basis. APS will accept DASRs for up to 3,500 customers per quarter beginning December 1, 1998 or the effective date of this Schedule, whichever is later. The quarter shall be closed once APS has accepted DASRs for the total number of customers eligible in that quarter. APS shall maintain a waiting list of up to 24,500 DASRs after the close of the first quarter. If the waiting list is full, no further DASRs will be accepted. Residential customer eligibility for Direct Access service is not site specific, and a residential customer that moves within APS' distribution service territory after becoming eligible for Direct Access service retains such eligibility. If a residential customer receiving Direct Access service returns to Standard Offer service, that customer must reapply for Direct Access eligibility through the DSR process. APS will periodically update the APS ESP Web Site with eligibility and waiting list status.
- 6.20. During the phase-in period (January 1, 1999 through December 31, 2000) ESPs are required to complete a Direct Access Load Aggregation Submittal form (DALAS) for those customers they choose to aggregate. DALAS forms will be accepted for customers with single premise non-coincident peak demand loads of 40 kW or greater (or greater than 16,500 kWh for one month of the last twelve (12) consecutive months if no demand load data is available) aggregated into a combined load of 1 MW or greater. The DALAS form shall be submitted to APS, at which point APS will review and approve the form, if it is complete and accurate in all material respects and satisfies the requirements for load aggregation. APS will notify the ESP if the DALAS form is valid within three (3) working days. Upon approval by APS, ESPs must submit the DASRs for the service delivery points indicated on the DALAS form within three (3) working days. DASRs received prior to DALAS form approval shall be rejected. DASRs received by APS within the 40 - 999 kW load ranges will be rejected if not participating in an APS approved load aggregation pool (i.e., complied with the DALAS process set forth in this Section). APS will begin accepting DALAS forms on November 25, 1998 or the effective date of this Schedule, whichever is later.
- 6.21. During the phase-in period (January 1, 1999 through December 31, 2000), the number of commercial and industrial customers eligible to participate in Direct Access will be based on the amount of megawatts available for competition under the Rules. For APS, 653 MWs of load is available on a first come, first served basis. APS will begin accepting DASRs for eligible customers (customers with a non-coincident demand of 1 MW and greater and those approved through the DALAS process) on December 1, 1998, or the effective date of this schedule, whichever is later, until such time that the available load is fulfilled. Eligibility for Direct Access service for commercial and industrial customers during the phase-in period is both customer and site specific. During the phase-in period only, APS shall not accept DASRs that specify a Direct Access switch date of more than sixty (60) calendar days from the date the DSR is submitted to APS.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

6.22 During the phase-in period (January 1, 1999 through December 31, 2000), all residential customers that produce or purchase at least ten percent (10%) of their annual electricity from photovoltaic or solar thermal energy resources that were installed in Arizona after January 1, 1997 shall be eligible for participation in Direct Access. Subject to the 653 MW limitation set forth in Section 6.21, all commercial customers that produce or purchase at least ten percent (10%) of their annual electricity from photovoltaic or solar thermal energy resources that were installed in Arizona after January 1, 1997 shall be eligible for participation in Direct Access. The ESP shall identify customers eligible for Direct Access under this Section. APS may implement processes to verify and track eligibility under this Section.

6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 Subject to availability, and pursuant to the terms in the ESP Service Acquisition Agreement, this Schedule #10, and applicable tariffs and the restrictions therein, ESPs may select among the following billing options:

7.1.1 APS COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL APSCOMPANY/ESP BILLING

7.2 APS COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to APS Company, or APS calculates ESP charges, and APS Company sends a consolidated bill containing both APS Company and ESP charges to the Customer. All charges by APS to the ESP for consolidated billing shall be at rates approved by the ACC.

7.2.2 APS Company Obligations:

7.2.2.1 If the ESP elects to send bill-ready data, APS Company shall include bill the ESP charges and send the bill either by mail or electronic means to the customer. APS Company is not responsible for computing or determining the accuracy of the ESP charges on the bill. APS Company is not required to estimate ESP charges if the expected bill ready data is not received nor is APS Company required to delay APS Company billing. Billing rendered on behalf of the ESP by APS Company shall comply with A.A.C. R14-2-16131612.

7.2.2.2 If the ESP elects to have APS calculate the ESP charges, APS shall update the customer's records to reflect ESP charges to the customer based upon the pre-defined ESP tariff or charges agreed upon between the ESP and the customer for the ESP's services. APS will calculate both APS and ESP charges, include all charges on the bill, and send the bill either by mail or electronic means to the customer.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

7.2.2.32 ~~APS Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP, the customer's rate schedule number or service offer. Any billing-related details of ESP charges may be provided as specified in the applicable tariff approved by the ACC. These items shall be printed with the APS bill or electronically transmitted to the customer.~~

7.2.2.43 ~~APS If Company shall processes Customer payments on behalf of the ESP. The ESP shall receive payment for its charges as specified in this Schedule # 10 at Section 7.7, Payment and Collection Terms.~~

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer APS Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

7.2.3.2. The ESP shall submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to APS Company's meter reading schedule, and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1. Bills under this option will be rendered once a month. Nothing contained in this Schedule #10 shall limit APS Company's ability to render bills more frequently consistent with APS Company's existing practices. However, if APS Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2. Except as provided in Section 7.2.4.1, APS Company shall require that all ESP and APS Company charges be based on the same billing period data.

7.2.4.3. ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by APS Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this ~~dated deadline~~, the last day of the APS bill processing window, APS Company will render ~~the a bill for APS Company charges only, without ESP charges.~~ The ESP must wait until the next billing cycle, unless there is a mutual agreement for APS Company to send an interim bill. If APS Company renders the bill for APS Company charges only, APS Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that APS Company charges were previously billed.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

7.2.4.4. ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, APS Company will render the customer's final bill for APS Company charges only, without the ESP's final charges. If APS Company renders the bill for APS Company charges only, APS Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must then produce a separate final bill for their charges, unless otherwise agreed upon by APS and the ESP send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5. Restrictions

7.2.5.1. Company APS UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under APS Company UDC Consolidated Billing.

7.3. ESP CONSOLIDATED BILLING

7.3.1. APS Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed APS Company charges to the extent that the ESP receives such detail from APS Company. The ESP is not responsible for the accuracy of APS Company charges.

7.3.2. APS Company Obligations:

7.3.2.1. APS Company shall calculate all APS its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. APS Company and the ESP may mutually agree to alternative options for the calculation of APS Company charges.

7.3.2.2. APS Company shall provide the ESP with sufficient detail of APS its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. APS Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If APS Company's billing charges have not been received by such date, the ESP may render the bill without APS Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including APS Company charges. If the ESP does not include such late received charges, the ESP shall bill the charges in the next available billing cycle after receipt of the billing data from APS. The ESP will include a message on the bill stating that APS Company charges are forthcoming.



SCHEDULE 10

TERMS AND CONDITIONS FOR DIRECT ACCESS

7.3.2.3 For a Physical Disconnect Final Bill, APS Company will provide the ESP with APS Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If APS Company's billing charges have not been received by such date, the ESP may render the bill without APS Company charges. ~~APS will then render a separate bill for the UDC charges, unless a mutual agreement is made between APS and the ESP to have a final bill produced and sent to the customer for the APS final charges. The ESP shall include a message on the bill stating that APS Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.~~

~~7.3.2.4 APS charges shall be calculated based on existing APS billing cycles regardless of which party provides the meter reading. APS charges shall be conveyed to the ESP electronically or by other means acceptable to both the ESP and APS.~~

7.3.3 ESP Obligations:

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill shall include any billing-related details of APS Company charges. The APS Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of APS Company by the ESP shall comply with A.A.C. R14-2-46131612.

7.3.3.3 Other than including the billing data provided by APS Company on the customer's bill, the ESP has no obligations regarding the accuracy of APS Company charges calculated by APS or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all APS charges due to APS Company and not disputed by the customer ~~as specified in pursuant to Section 7.7.2.1 of this Schedule # 10.~~

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer ~~customers~~ Customers customized billing cycles or payment plans which permit the Customer to pay the ESP for APS Company charges in different amounts than APS Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company APS charges as ~~billed by APS in full.~~ Should the Customer select an optional payment plan, all APS Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

~~7.3.4.1~~ ESPs may render bills more or less frequently than once a month. However, APS Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

7.4 DUAL COMPANY APS/ESP BILLING

~~7.4.1~~ APS Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company APS and the ESP. APS Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All APS customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, APS Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If APS Company is providing consolidated Consolidated billing services, APS Company shall continue to mail provide these notices in the billing envelope and may use the billing envelope as it does in current practices for providing such information.

7.5.2 Under APS Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable APS Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or APS Company if providing such services) shall resolve any meter errors and must notify the ESP and APS Company, as applicable, so any billing adjustments can be made. ~~Additionally, All other affected parties, including the~~ appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of the Customer's electrical usage energy or demand. If the MSP, MRSP, ESP or APS Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and APS Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and APS Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 APS Company UDC Consolidated Billing

7.6.1.3.1 APS Company shall be responsible for notifying the Customer and adjusting the bill for APS its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges ~~if the ESP is providing bill ready data~~. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to the Customer's next normal monthly bill, unless there is mutual agreement to have APS Company send an interim bill to the customer including the ESP's charges.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

~~7.6.1.3.3~~ APS shall be responsible for any recalculation related to the ESP charges if APS is calculating the ESP charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges attributable to a ~~fast meter~~ from its current and prior ESPs, as appropriate.

7.6.1.4.2 APS Company shall transmit its adjusted APS charges and any refunds for overcharges to the ESP with the Customer's next normal monthly bill. The ESP shall apply the charges to the Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to the Customer including the APS Company charges.

7.6.1.5 Dual APS Company/ESP Billing

~~7.6.1.5.1~~ APS Company and the ESP shall be separately responsible for notifying the Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 APS Company UDC Consolidated Billing

7.7.1.1 APS Company shall remit payments to the ESP for the total ESP charges collected from the Customer within three (3) working days after the Customer's payment is received. APS Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by APS Company.

7.7.1.2 The Customer is obligated to pay APS Company for all undisputed APS Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and APS Company.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

7.7.1.4 Payment for any APS Company charges for APS UDC Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date APS Company charges are rendered to the ESP. ~~All charges received after fifteen (15) calendar days~~ Any payment ~~not received within this time frame~~ will be assessed applicable late fees ~~charges~~ pursuant to Schedule # 1. If an ESP fails to pay these charges prior to the next billing cycle, APS Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 of this Schedule # ~~10~~ may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 The ESP shall pay amounts owed to APS for undisputed APS charges whether or not the customer has paid the ESP. Payment is due in full from the ESP within fifteen (15) calendar days after the date APS Company's charges are rendered to the ESP. The ESP shall pay all undisputed APS Company charges due APS regardless of whether the Customer has paid the ESP. All ~~charges~~ payments received after fifteen (15) calendar days will be assessed applicable late fees ~~charges~~ pursuant to Schedule # 1. If an ESP fails to pay these charges prior to the next billing cycle, APS Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 of this Schedule # ~~10~~ may be required.

7.7.2.2 APS Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 APS Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual APS Company/ESP Billing

~~7.7.3.1~~ APS Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 APS Company UDC Consolidated Billing

7.8.1.1 APS Company shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

7.8.1.2 All Ceustomer payments shall be applied first to unpaid balances identified as APS Company charges until such balances are paid in full, then applied to ESP charges. A Ceustomer may dispute charges as provided by A.A.C. R14-2-212 and this Schedule # 10, but a Ceustomer will not otherwise have the right to direct partial payments between APS Company and the ESP.

7.8.1.3 ACC rules shall apply to late or non-payment of all APS Company customer charges. Undisputed APS Company delinquent balances owed on a Ceustomer account shall be considered late and subject to APS Company late payment procedures by APS.

7.8.2 ESP Consolidated Billing

~~7.8.2.1~~ The ESP shall be responsible for collecting both unpaid ESP and APS Company charges, sending notices informing Ceustomers of unpaid ESP and APS Company balances, and taking appropriate actions to recover the amounts owed. APS Company shall not assume any collection obligations under this billing option and ESP is liable to APS Company for all undisputed payments owed APSCcompany.

7.8.3 Dual APSCcompany/ESP Billing

~~7.8.3.1~~ APS Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Ceustomers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Ceustomer disputes with APS Company charges must be directed to APSCcompany.

7.9 Service Disconnects and Reconnects

~~7.9.1~~ In accordance with ACC rules, APS Company has the right to disconnect electric service to the Ceustomer for a variety of reasons, including, but not limited to, the non-payment of APS Company's final bills or any past due charges by the Ceustomer, or evidence of safety violations, energy theft, or fraud, by the Ceustomer. The following provides for service disconnects and reconnects.

~~7.9.1.1~~ APS Company shall notify the Ceustomer and the Ceustomer's ESP of APS Company's intent to disconnect electric service for the non-payment of APS Company charges prior to disconnecting electric service to the Ceustomer. APS Company shall further notify the ESP at the time the Ceustomer has been disconnected. To the extent authorized by the ACC, a service charge shall be imposed on the Ceustomer if a field call is performed to disconnect electric service.

~~7.9.1.2~~ APS Company shall reconnect electric service for an ACC-authorized service fee when the criteria for reconnection have been met to APS Company's satisfaction. APS Company shall notify the ESP of a Ceustomer's reconnection.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

7.9.1.3 ~~APS Company~~ shall not disconnect electric service to the ~~Ceustomer~~ for the non-payment of ESP charges by the ~~Ceustomer~~. In the event of non-payment of ESP charges by the ~~Ceustomer~~, the ESP may submit a DASR requesting termination of the service agreement and request return to ~~APS Company~~ Standard Offer Service. ~~APS Company~~ will then advise the ~~Ceustomer~~ that they will be placed on ~~APS Company~~ Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10. Involuntary Service Changes

7.10.1. ~~Service Changes~~A Customer may have its service of electricity, billing, or metering from an ~~ESP changed to another provider, including Company, involuntarily in the following circumstances:~~

~~7.10.1.1. A customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including APS, involuntarily in the following circumstances:~~

7.10.1.1.1. The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.1.2.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with ~~APS Company~~ (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and ~~APS Company~~ exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.1.3.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and ~~APS Company~~ exercises a contractual right to change billing options.

7.10.1.1.4.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator ~~wherever~~ whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.1.5.5 The ~~Ceustomer~~ fails to meet its Direct Access requirements and obligations under the ACC rules and ~~APS Company~~ tariffs and schedules.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

7.10.2. Change of Service Election in Exigent Circumstances

~~7.10.2.1.~~ In the event APS Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule #10 or the ESP Service Acquisition Agreement such that APS Company elects to invoke its remedies under this Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.4.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, APS Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, APS Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule #10. APS Company shall provide such notice and opportunity to ~~cure~~ remedy the problem if there are reasonable circumstances prevailing as is reasonable under the circumstances, if any is reasonable. Additionally, APS Company shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by APS Company. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the Customer other than as provided in Section 4.4.2 of this Schedule #10.

7.10.3. Change in Service Election Absent Exigent Circumstances

7.10.3.1. In the event APS Company finds that an ESP has materially failed to meet its obligations under this Schedule #10 or the ESP Service Acquisition Agreement such that APS Company seeks to invoke its remedies under this Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.4.3), and the failure does not constitute an emergency (as defined in Section 7.10.2.4) or involve an ESP's unauthorized energy use, APS Company shall notify the ESP and the ACC of such finding in writing stating the following:

- 7.10.3.1.1. The nature of the alleged failure;
- 7.10.3.1.2. The actions necessary to ~~cure~~ remedy the failure;
- 7.10.3.1.3. The name, address and telephone number of a contact person at APS the Company authorized to discuss resolution of the failure.

7.10.3.2. The ESP shall have thirty (30) calendar days from receipt of such notice to ~~cure~~ remedy the alleged failure or reach an agreement with APS Company regarding the alleged failure. If the failure is not ~~cured~~ remedied and no agreement is reached between APS Company and the ESP following this thirty (30) day period, APS Company may initiate the DASR process set forth in this Schedule #10 to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2 of this Schedule #10.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

7.10.4. Termination of ESP Consolidated Billing

~~7.10.4.1. ESP Consolidated Billing may be terminated under the circumstances set forth in this Section 7.10.4. This Section 7.10.4 sets forth the notice and opportunity to cure provisions applicable to defaults that permit a remedy of terminating ESP Consolidated Billing under this Schedule # 10 (which is incorporated by reference in the ESP Service Acquisition Agreement)~~

~~7.10.4.2.1. APS Company may terminate ESP Consolidated Billing under the following circumstances:~~

~~7.10.4.2.1.1. If APS finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete or inaccurate; the ESP attempts to avoid payment of ACC authorized APS charges; or the ESP files for bankruptcy, fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days; admits insolvency; makes a general assignment for the benefit of creditors; is unable to pay its debts as they mature; or has a trustee or receiver appointed over all or a substantial portion of its assets, APS shall notify affected customers that ESP Consolidated Billing services will be terminated, and APS may switch affected customers to Dual Billing as promptly as possible. The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:~~

~~7.10.4.1.1.1. Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.~~

~~7.10.4.1.1.2. The ESP attempts to avoid payment of Company charges.~~

~~7.10.4.1.1.3. The ESP files for bankruptcy.~~

~~7.10.4.1.1.4. The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.~~

~~7.10.4.1.1.5. The ESP admits insolvency.~~

~~7.10.4.1.1.6. The ESP makes a general assignment for the benefit of creditors.~~

~~7.10.4.1.1.7. The ESP is unable to pay its debts as they mature.~~

~~7.10.4.1.1.8. The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.~~



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 7.10.4.1.2.2. If the ESP fails to pay APS Company (or dispute payment pursuant to the procedures set forth in this Schedule # 10) the full amount of all APS Company charges and fees by the applicable due date, APS Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than ~~three (3)~~ two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by APS Company, APS Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.
- 7.10.4.1.2.3. If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from APS Company of any additional credit, security or deposit requirements set forth in Sections 5.1.4 and 7.11 of this Schedule # 10, APS Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.
- 7.10.4.32. Upon termination of ESP Consolidated Billing pursuant to this Section 7.10.4, APS Company may deliver a separate bill for all APS Company charges which were not previously billed by the ESP.
- 7.10.4.43 APS Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.34 and 7.11, and payment to APS Company of all costs associated with changing ESP customers' billing elections to and from dual billing.
- 7.10.4.54 In the event APS Company terminates ESP Consolidated Billing, APS Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.
- 7.10.5. Termination of APS Company UDC Consolidated Billing
- 7.10.5.1. APS Company may terminate APS Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to timely pay APS Company charges in connection with APS Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2 of this Schedule # 10.
- 7.10.5.2 APS Company may terminate APS UDC Consolidated Billing upon providing thirty (30) days notice to an ESP if APS Company cancels or changes the tariff governing APS Company UDC Consolidated Billing.
- 7.10.6. Upon termination of ESP Direct Access services pursuant to this Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by the Customer, APS Company shall provide such services, until such time that the Customer makes an election.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

7.10.7. APS Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11. ESP Security Deposits

7.11.1. APS Company may, ~~in~~ at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to ~~timely~~ pay APS Company charges or ACC-approved Direct Access charges ~~within the established time frame~~, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through this Schedule #10 and APS Company's other tariffs and schedules.

7.11.2. The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3. Security deposits required pursuant to this Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.67.3.4 of APS Company Schedule #1. APS Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4. APS Company may refuse to accept DASRs from, or provide other APS Company services to, an ESP that fails to comply ~~within~~ thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to this Section 7.11.

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, ~~Meter Service Provider (MSP)~~ and ~~Meter Reading Service Provider (MSRP)~~ services.

8.2 APS Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for Residential Load-Profiled Customers

~~8.2.2 All competitive Metering or Meter Reading services whenever there are no authorized providers available to supply services to a particular class of customers or location.~~

~~8.2.3~~ 8.2.2 Services as authorized by the ACC.

~~8.2.4~~ 8.2.3 APS Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for APS Company charges.

8.3 ~~An~~ Load Serving ESP may sub-contract Metering or Meter Reading Services to a qualified ~~certificated~~ third party. If the ESP sub-contracts any of the components of these services to a third party, the ESP shall, for the ~~proposes~~ purposes of this Schedule #10, remain responsible for the services.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or APS Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test
ANSI 57.13	Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 National Electric Code (NEC) & Local Requirements by jurisdictions

8.5.6 APS Company's Electric Service Requirements Handbook/Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the customer's APSC company's rate tariff schedules.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.6.2 If APS Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with APS Company's meter reading system.

8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet APS existing approved specifications, as set forth in APS Company's Electric Service Requirements Manual SRM, or is in violation of any code listed in Section 8.5 in place at the time of installation.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh only kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh only kWh Electro-Mechanical	Trouble	Meter Calibration Test
1 Ph TOU or Solid State kWh Hybrid or Solid State	Routine	Reprogram and Meter Inspection Meter Test
1 Ph TOU or Solid State(all)	Trouble	Meter Calibration Test
3 Ph Meters (all)	All	Meter Calibration Test
1 Ph or 3 Ph IDR Meters	All	Meter Calibration Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.34 Records on calibration meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest calibration meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

8.8.1 Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify APS Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and APS Company shall use a Direct Access Meter Notification form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

8.9 Meter Identification

- 8.9.1 The ESP or its agent shall install an APS Company provided unique meter number on each meter. APS Company will provide the unique meter numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.
- 8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name of the load serving ESP's name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

- 8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and APS Company's Electric Service Requirements Manual.
- 8.10.2 An ESP or its agent must be authorized by APS Company to remove an APSa Company owned meter or PTs and CTs. Once authorized, when the ESP or its agent intends to remove an APS meter with or without CTs and PTs and install a new meter with or without CTs and PTs in its place, APS must first receive a completed Direct Access Meter Notification Form. This must be submitted to APS at least five (5) working days prior to the meter set. Under no circumstances shall an ESP or its agent remove APS metering or metering equipment without prior notification to APS. Notwithstanding the foregoing, ESP or its agent shall schedule a meter exchange so that the Direct Access Meter Notification Form is received by APS by the end of business six (6) working days before the scheduled read date. During the phase-in period (January 1, 1999 through December 31, 2000) the meter exchange must be completed within 60 days of the date that the RQ-DSAR is submitted. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.
- 8.10.3 The ESP or its agent shall inform APS Company of all meter activity, such as meter installations, or exchanges, CT and PT exchanges via the Direct Access Meter Notification Form Meter Activity Coordination (MAC) Form within the time frames specified above. Additionally, ESP must provide APS with the most recent meter calibration test data. If final meter reads are not provided to APS Company, are inaccurate, or otherwise result in APS Company not being able to render accurate final bills to customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.10.4 The ESP or its agent shall return the existing meter with any removed PTs and CTs to APS Company at one of APS Company's designated locations throughout APS service territory identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 APS Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in the APS Company's Electric Service Requirements Manual, ESRM, and the APS Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements. APS Company shall perform a pre-installation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 APS Company may require a site meet for: to exchange or remove the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which APS Company forbids key access; co-generation sites, bi-directional or detented metering sites; or on upon request of an ESP or MSP. The ESP and APS Company's MAC shall coordinate the time of the site meet. If the ESP or MSP misses two (2) site meets, APS Company may cancel the applicable DASR. APS Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to APS Company, an ESP, or the customer. The customer must obtain the meter through APS Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to APS Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 If the ESP or customer owns the meter, the ESP must own the CTs, PTs and associated equipment, except as provided in section 8.12.3. The ESP may purchase existing CTs and PTs and associated metering equipment from APS.

8.12.3 The following provisions apply to the ownership of CTs and PTs:



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

8.12.3.1 For distribution voltages up to 25kv, the ESP or APS shall own the CTs and PTs. For transmission primary voltages (over 25kv), the CTs and PTs shall be owned by APS. ESP owned CTs & PTs must meet APS specifications. No CTs and PTs or associated metering equipment shall be set or allowed to remain in service if it is determined that the CTs and PTs or its associated equipment did not meet APS' approved specifications, as set forth in APS' Electric Service Requirements Manual, in place at the time of installation.

8.12.43 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in the APS Company's Electric Service Requirements Manual ESRM. During meter exchanges, the ESP or its agent's employees who are certified-certificated to perform the related MSP activities may install, replace or operate APS Company test switches and operate APS Company-sealed customer-owned test blocks.

8.12.5 Direct Access premises with multiple service entrance sections will be considered separately for metering purposes. Existing totalizing installations will be discontinued upon a customer's entrance into Direct Access.

8.13 Installation Options

8.13.1 The ESP may choose from the following list of options for meter installation: The ESP is responsible for Direct Access customer meter installation. Company may optionally provide meter installation pursuant to the Rules.

8.13.1.1 ESP-owned/ESP-installed metering

8.13.1.2 ESP-owned/APS-installed metering

8.13.1.3 Customer-owned/ESP-installed metering

8.13.1.4 Customer-owned/APS-installed metering

8.13.1.5 APS-owned/APS-installed metering.

8.13.2 ESPs or their agents must be certified-certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP service provider and his their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certified-certificated Metering Service Provider MSP.

8.13.2.2 Subcontracting with a third party that is a certified-certificated MSP.

8.13.2.3 Subcontracting with APS Company under the circumstances described in Section 8.2 of this Schedule # 10.

8.14 As part of providing metering services, ESPs or their agents shall:



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 8.14.1 Obtain lock ring keys for meters originally installed by ~~APS Company~~ or request site meets with ~~APSCompany~~. ~~APS Company~~ will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the ~~APS Company~~ MAC.
- 8.14.2 If lock rings are used they shall meet ~~APS Company~~ requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from ~~APSCompany~~.
- 8.14.3 Provide information to ~~APS Company~~ on the specifications and other specifics on meters not purchased from or installed by ~~APSCompany~~.
- 8.14.4 For customers transferring from Direct Access to Standard Offer service, the ESP shall either allow ~~APS~~ to remove the customer's meter, or schedule a joint meet to remove the meter. Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows ~~APS Company~~ to remove meters, ESP shall coordinate with the ~~APS Company~~ MAC regarding the return of ESP's the meters.
- 8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.
- 8.14.6 Ensure that ESP and MSP employees working in ~~APS Company's~~ territory follow ACC, and other applicable safety standards.
- 8.14.7 In the event that unauthorized energy use is suspected and a safety hazard exists, notify APS immediately, or within twenty-four (24) hours for non-safety issues, and cooperate with APS in response thereto. Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.
- 8.14.8 ~~ESPs and their agents shall take~~ Take no action to impede ~~APS' Company's~~ safe and unrestricted access to a customer's service entrance.
- 8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

8.15 MRSP-MSRP Services provided as a responsibility of an ESP

8.15.1 MRSP functions shall be performed by certified MRSPs on the ESP's behalf in accordance with ACC regulations, and shall be the responsibility of the party specified in the DASR. MRSP obligations and responsibilities are as stated in the ACC's Rules and requirements and include: Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next schedules read date. MSRP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1.1— Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to ACC-approved standards Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.

8.15.1.2 Both APS Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.

8.15.1.3 Meter read data shall include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must shall be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated reads, along with reasons for the estimate, shall be included with the reads on the MRSP server. The EDI format specification includes the estimated read reason codes to be used data shall contain applicable reason codes pursuant to the 867 guidelines.

8.15.1.4 The MRSP shall provide APS Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.1.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.1.6 MRSPs shall read the Customer's meter on the APS read cycle. MRSP shall provide APS with meter reading data in a manner that conforms to APS' billing cycles in accordance with A.A.C. R14-2-209 based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.



SCHEDULE 10 TERMS AND CONDITIONS FOR DIRECT ACCESS

- 8.15.4.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by APS Company or the Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters.

- 8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.
- 8.16.1.2 Meter read date and time shall be accurate.
- 8.16.1.3 All meter reading data shall be validated with the applicable ACC approved requirements pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

~~8.16.2.1 Pursuant to guidelines established by the Utilities Division Director, timeliness requirements for the delivery of data. One hundred percent (100%) of the validated meter reads data shall be available by 3:00 p.m. local Arizona time (MST) on the third working day after the scheduled read date. If the meter reads are data is not posted, or available is unavailable, or are posted clearly in error by 3:00 p.m. on the third working day after the scheduled read date contains errors by this deadline, the read-billing determinants including usage (kWh) and demand (kW) may be estimated or read by APS by Company and the ESP shall be charged an approved charge for this service. For newly installed IDR meters, IDR reads shall include the meter read, the interval data and enough information to calculate the read and total consumption to the exact cut-over date and time.~~

8.16.3 Proof of Operational Ability

~~8.16.3.1 Prior to performing MSRP MRSP services in APS' Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each MSRP MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in APS Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in APS' Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in APS Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MSRP MRSP successfully demonstrates its operational ability.~~

8.16.4 Retention and Format for Meter Reading Data

- 8.16.4.1 All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in APSC Company-compatible EDI format.

8.17 APSC Company performing MSP and MRSP functions:

~~8.17.1~~ If APSC Company is eligible to perform Direct Access related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

~~8.17.1.1~~ For the period January 1, 1999 to December 31, 2000 for load profiled customers in which APS is reading the meter, ~~the~~ validated meter read will be posted in EDI format no later than six (6) working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever APSC Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected Customer in question. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party will may be charged an ACC-approved tariff for the meeting.

8.18.2.2 APSC Company may repair the defect, and the other party shall be responsible for all related expenses.

8.18.2.3 Upon a demonstrated pattern of non-compliance (with ACC requirements and this Schedule #10) and failure to correct the problem in a timely manner, APS may give written notice to the non-compliant party and to the ACC. After five (5) working days, APS may suspend processing DASRs from an ESP that uses an MSP or MRSP that is non-compliant until such non-compliance is corrected to APS' satisfaction. Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

~~8.18.2.4~~ A pattern of non-compliance by an ESP is defined by the following conditions:

~~8.18.2.4.1~~ If more than one percent (1%) of the service accounts served by an ESP, or five (5) accounts, whichever is greater, are found to be non-conforming and are not corrected during the first six months of Direct Access participation by that ESP.

~~8.18.2.4.2~~ More than one-half of one percent (0.5%), or three (3) accounts, whichever is greater, are found to be non-conforming and are not corrected during any six consecutive months thereafter.



SCHEDULE 10
TERMS AND CONDITIONS FOR DIRECT ACCESS

- 8.18.3 APS Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to Section 7.10.1.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.



SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION
OF SPECIALIZED METERING

Arizona Public Service Company (Company) will provide specialized metering upon customer request, provided the customer agrees to the following conditions:

1. The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR and KYZ pulse meters. The customer must specify whether a modem will be required.
2. If the customer requests a meter with a modem option, the customer will be required to install communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within five to ten feet of the meter panel location and in such a manner that will provide for ease of attachment of the jack to the meter panel by Company. The phone line must be installed prior to the installation of the meter. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).
3. If a customer requests kWh pulses, Company shall furnish an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.
4. The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:
 - 4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.
 - 4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.
 - 4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

Company will retain ownership of all meters and Company installed metering equipment.

If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.



SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION
OF SPECIALIZED METERING

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the customer stop the operation or in any way affect or interfere with the operation of the isolation relay and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.
6. Company reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the customer's demand control or other equipment. However, Company will make a good faith effort to notify the customer prior to any interruption of the specialized metering circuit.
7. The possible failure or malfunction of an isolation relay and subsequent loss of kWh contact closures to the customer's control equipment shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the kWh and demand record for billing purposes.
8. The accuracy of the customer's equipment is entirely the responsibility of the customer. Should the customer's equipment malfunction, Company will reasonably cooperate with the customer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the customer, unless the actual source of the malfunction is found within Company's equipment.
9. If Company provides pulse values in kWh, customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.
10. No circuit for use by the customer shall be installed from Company's billing metering potential or current transformer secondaries.
11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the customer.
12. Upon request by Company, the customer shall make available to Company monthly load analysis information.
13. References to electric kWh pulses above shall mean isolation relay contact closures only; the customer is required to furnish operating voltage service. Isolation relay contacts are rated 5 amps, 28 volts DC or 120 volts AC.
14. The customer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of specialized metering.



SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION
OF SPECIALIZED METERING

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.
16. Prior written approval by an authorized Company representative is required before electric kWh pulses service may be implemented.





SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION
OF SPECIALIZED METERING

Arizona Public Service Company (Company) Electric KWH pulses will be provided specialized metering upon customer request, provided by Company if Customer's billing metering equipment is of the type dependent on pulses proportional to KWH to drive the demand meter, and the Customer agrees to the following conditions:

1. Company will provide electric KWH pulses to Customer who can demonstrate the capability of using such KWH pulses for the purposes of load shaping. The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR and KYZ pulse meters. The customer must specify whether a modem will be required.
2. Customer shall submit a plan and wiring diagram for the proposed use of the electric KWH pulses for prior approval by Company's Electric Meter Section. If the customer requests a meter with a modem option, the customer will be required to install communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within five to ten feet of the meter panel location and in such a manner that will provide for ease of attachment of the jack to the meter panel by Company. The phone line must be installed prior to the installation of the meter. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).
3. The Company (through its Electric Meter Section) shall furnish, install and maintain: If a customer requests kWh pulses, Company shall furnish an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.
 - 3.1 The isolation relay, in connection with providing KWH pulses, in the billing metering compartment of the service entrance switchboard, and
 - 3.2 The output wires and connections from this relay to an approved terminal block to be furnished by Customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) Company metering compartment and not on the face of Company metering panel.
4. Customer shall pay the complete installation cost of the isolation relay and output wiring as set forth above, as a non-refundable contribution. The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:
 - 4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.
 - 4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.
 - 4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.



SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION
OF SPECIALIZED METERING

Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

Company will retain ownership of all meters and Company installed metering equipment.

If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the cCustomer stop the operation or in any way affect or interfere with the operation of the isolation relay and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.
6. Company reserves the right to interrupt the specialized metering pulse circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the cCustomer's demand control or other equipment. However, Company will make a good faith effort to notify the cCustomer prior to any interruption of the pulse specialized metering circuit.
7. The possible failure or malfunction of an isolation relay and subsequent loss of KWH kWh contact closures to the cCustomer's control equipment; shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the KWH kWh and demand record for billing purposes.
8. The accuracy of the cCustomer's impulse totalizer and demand control equipment is entirely the responsibility of the cCustomer. Should the cCustomer's equipment malfunction, Company will reasonably cooperate with the cCustomer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the cCustomer, unless the actual source of the malfunction is found within Company's equipment.
9. If Company provides The pulse values in KWH kWh, provided by Company will be those in use by Company's billing metering system. cCustomer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates, should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.
10. No circuit for use by the cCustomer shall be installed from Company's billing metering potential or current transformer secondaries.
11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the cCustomer.



SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION
OF SPECIALIZED METERING

12. Upon request by Company, the cCustomer shall make available to Company monthly load analysis information ~~showing the effect of Customer's load regulation.~~
13. References to electric ~~KWH-kWh~~ pulses above shall mean isolation relay contact closures only; the cCustomer is required to furnish operating voltage service. Isolation relay contacts are rated 5 amps, 28 volts DC or 120 volts AC.
14. The cCustomer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of electric ~~KWH pulses by Company on Customer's side of the isolation relays~~ specialized metering.
15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.
16. Prior written approval by an authorized Company representative is required before electric ~~KWH-kWh~~ pulses service may be implemented.

Testimony
of

Kenneth

Gordon, Ph.D.

**BEFORE THE
ARIZONA CORPORATION COMMISSION**

**TESTIMONY OF
KENNETH GORDON, Ph.D.**

**ON BEHALF OF
ARIZONA PUBLIC SERVICE COMPANY**

June 27, 2003

TABLE OF CONTENTS

I.	QUALIFICATIONS, SUMMARY AND CONCLUSIONS	1
II.	A BRIEF HISTORY OF THE RELEVANT ARIZONA CIRCUMSTANCES.....	7
III.	CONSISTENT REGULATORY COMMITMENT IN AN ERA OF TRANSITION	9
A.	UTILITIES AND THE REGULATORY COMPACT	10
B.	THE REVERSAL OF THE 1999 SETTLEMENT AGREEMENT	14
IV.	VERTICAL INTEGRATION, ORGANIZATIONAL EFFICIENCY, AND REGULATION.....	15
V.	WITNESS RESUME	APPENDIX A

1 **I. QUALIFICATIONS, SUMMARY AND CONCLUSIONS**

2 **Q. Please state your name and business address.**

3 A. My name is Dr. Kenneth Gordon. I am a Special Consultant with National Economic
4 Research Associates, Inc. ("NERA"), One Main Street, Cambridge, MA 02142.
5 Previously, I was a Senior Vice President at NERA. My Curriculum Vitae is attached
6 to this testimony as Appendix A..

7 **Q. Please state your qualifications.**

8 A. I am an economist and former Chairman of both the Maine Public Utilities Commission
9 ("Maine PUC") and the Massachusetts Department of Public Utilities ("Mass. DPU").¹

10 I have been an economist since 1965, and I have been directly involved with developing
11 and establishing regulatory policy at the federal and state levels since 1980, when I
12 became an industry economist at the Federal Communications Commission ("FCC").

13 I received my A.B. degree from Dartmouth College in 1960. I received my M.A.
14 degree in 1963 and my Ph.D degree in 1973, both in economics, from the University of
15 Chicago. I have taught applied microeconomics, industrial organization, and regulation
16 (as well as other subjects) at Georgetown University, Northwestern University,
17 University of Massachusetts at Amherst, and Smith College.

18 From 1980 to 1988, I was an industry economist at the FCC's Office of Plans and
19 Policy, where I worked on a full range of regulatory issues, including
20 telecommunications, cable, broadcast, and intellectual property rights. At the FCC, a
21 major focus of my work was on activities aimed at introducing competition into
22 communications markets.

23 Prior to joining NERA in November 1995, I chaired the Maine PUC (1988 to December
24 1992) and then the Mass. DPU (January 1993 to October 1995). During my term as
25 chairman of the Mass. DPU, the DPU investigated and approved a price cap incentive
26 regulation plan for NYNEX (now part of Verizon Corporation), and also undertook a

¹ The Mass. DPU is now known as the Massachusetts Department of Telecommunications and Energy.

1 proceeding to examine interconnection and other issues related to the development of
2 competition at all levels of telecommunications, including basic local service.

3 While I was its Chairman, the Mass. DPU issued a series of orders aimed at the reform
4 of electric rate regulation, including revisions to integrated resource management
5 procedures, the introduction of incentive regulation, policy issues related to the
6 regulatory treatment of mergers and acquisitions, and the design of electric industry
7 restructuring. I was heavily involved in developing Massachusetts' plan to introduce
8 competition in retail electric markets in that state, and the concurrent efforts to establish
9 practical policies to address stranded costs and other transitional issues that arise in
10 restructuring the electric utility industry. While in Massachusetts, I co-chaired the
11 Governor's task force on electricity competition.

12 While a regulator, I was active in the National Association of Regulatory Utility
13 Commissioners ("NARUC"), serving on its Communications and Executive
14 Committees. In 1992, I served as President of NARUC. I was also Chairman of the
15 BellCore Advisory Committee and the New England Governor's Conference Power
16 Planning Committee.

17 **Q. Please describe the overall situation in which, in your opinion, Arizona Public**
18 **Service Company ("APS" or the "Company") finds itself, and the consequences of**
19 **that position.**

20 **A.** There are five points to emphasize. First, in spite of the fact that its market is open to
21 choice at the retail level, in a practical sense APS continues to have, in its traditional
22 service territory, obligations to serve customers, whether as provider of last resort
23 ("POLR) or otherwise, that are similar to those it had while operating on a sole-provider
24 basis. It must provide safe and reliable power to its customers, in as efficient a manner
25 as reasonably possible. Second, and closely related to this, APS remains a traditional
26 utility from a ratemaking perspective, with its rates regulated based on traditional rate-
27 of-return-regulation/cost of service principles. While APS' rates have been modified in
28 the past several years by price reductions and/or freezes agreed to through a negotiated
29 process, and approved by the Arizona Corporation Commission ("Commission"), the

underlying process for setting its rates, along with other terms and conditions of service, remains the same. Third, Arizona's regulatory framework must allow APS sufficient flexibility to meet its basic responsibilities of providing reliable power, even as the Commission continues to explore other possible configurations of the industry in the state. Fourth, the Company has experienced unanticipated turns in the regulatory policies that govern it. These reversals of policy could threaten the ability of APS to satisfactorily meet its obligations to its customers unless the Commission addresses the impacts of its policy reversal in a timely and responsible manner. Finally, while the central focus of regulatory policies should be on consumers, careful attention to investors' interests is an essential part of that process and, if done properly, is directly aligned with long-term consumer interests.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to help provide a policy framework for properly regulating APS in the circumstances that utility is in today. As an economist and former Chairman of two state regulatory commissions, I discuss some basic principles of regulation and indicate how they are relevant in the circumstances now faced by APS.

The Commission has moved in the direction of competition in electric generation, although this movement has slowed given recent changes in its regulatory policy, conditions in Western energy markets, and capital markets. Nevertheless, on the federal level (and in many states as well), regulators continue to focus on developing regulatory policies that support competition in generation, while continuing to regulate transmission (and, at the state level, distribution) as natural monopolies. As the Commission is well aware, there is less uniformity in policies with respect to retail competition.

The rate case proceeding that APS is filing is the "next step" in an emerging regulatory process that has already undergone a sharp change in direction with respect to the ownership of generation, but has yet to set a firm new course. In its decision in this proceeding, the Commission faces a number of important questions and, in particular,

1 will have to deal with the consequences of having reversed an important element of its
2 regulatory policies. The Commission will also have to decide where it wants APS to go
3 from here, keeping in mind that APS cannot be an efficient and reliable service provider
4 if it is expected to be "all things to all people," and that APS must have the financial
5 and economic capability needed to accomplish its mission. My goal, in offering these
6 policy recommendations, is to identify and provide an analysis of critical regulatory
7 issues raised by the Commission's recent Orders. It is important to note that my
8 conclusions and comments are based on circumstances that are specific to the situation
9 that the Commission, APS, and APS' customers face in Arizona, and may or may not be
10 applicable to other situations.

11 Going forward, it is important that regulatory policies be carried out in such a way as to
12 provide APS with the means to provide efficient, safe, adequate, and reliable service to
13 customers. As part of the process, APS should have an opportunity to recover its
14 reasonable costs of providing service, including its allowed cost of capital. In other
15 words, regulatory policies need to allow APS to keep the "lights on" as efficiently as
16 possible. The focus should be on efficiency and consumer benefits—and APS must be
17 able to raise capital when needed at reasonable prices if these goals are to be achieved.

18 **Q. Please describe the special features of the competitive/regulatory situation in**
19 **Arizona with respect to APS.**

20 **A.** The Commission has recently begun to re-frame the policy framework under which the
21 Company operates. The Track A Order² reverses the Commission-ordered transfer of
22 APS' generation assets to a separate corporate affiliate, thereby disrupting the balancing
23 of interests contained in the 1999 Settlement Agreement, which included: (1) a
24 significant write-off of regulatory assets by the Company; and (2) a series of substantial
25 rate decreases for customers.

26 The Commission's decision to modify its regulatory policies regarding APS' planned
27 transfer of its generation to its non-utility affiliate, Pinnacle West Energy Corporation
28 ("PWEC"), represented a major policy reversal. Foreclosing the transfer of generation

² Decision No. 65154 (September 10, 2002).

1 changed an important component (arguably the most important component) of the 1999
2 Settlement Agreement for APS, which provided for a complex series of tradeoffs
3 among the interested parties, and had been agreed to by a number of parties and
4 approved by the Commission. APS' current inability to configure its generation
5 operations in a single entity, as originally envisioned, is a particular concern.

6 The Commission must now determine the proper level of the rates APS charges to its
7 retail customers, using a traditional regulatory process. In addition, the Commission
8 must resolve a number of issues that were left for future determination in earlier
9 proceedings. These include: (1) the proper rate treatment of the PWEC generating
10 assets built within that entity, but which now find themselves operating alone, without
11 the complementary generation of APS that was to have been moved to PWEC to serve
12 APS; (2) the rate treatment of the regulatory assets (\$234 million pretax) that had been
13 written off; and (3) the rate treatment of transition costs associated with the planned
14 transfer of generating assets to PWEC.

15 **Q. What conclusions have you drawn?**

16 **A.** I have drawn the following conclusions:

- 17 • *The regulatory compact assures investors of fair and reasonable treatment, and*
18 *thereby helps ensure reasonably priced capital.* Given the basic financial fact of
19 life that if the utility is to meet its service obligations, it must have a meaningful
20 opportunity to recover its just and reasonable costs of doing business, including the
21 cost of capital, regulators are obligated to treat the utility and its owners reasonably.
22 Importantly, this is also beneficial to the utility's ratepayers in the longer term
23 because it helps to moderate the utility's cost of capital and allows it the financial
24 strength to invest in service quality and reliability. Regulators should strive to act in
25 a way that minimizes the regulatory risks to investors and compensates them for that
26 risk.
- 27 • *In the current environment, utilities, such as APS, face significant risks, particularly*
28 *regulatory ones.* This is especially true, of course, when regulators feel they should
29 be making changes in regulatory policies. However, once a regulatory agency re-
30 sets its direction, it must move forward in a way that treats the utility in a reasonable
31 manner prospectively and which "settles up" the costs reasonably incurred in
32 reliance upon the "old" policy. Over the longer term such equitable treatment will
33 benefit customers as well.

- 1 • *The Commission needs to address the consequences stemming from its decision to*
2 *halt divestiture.* As applied to this case, the above conclusions mean that the
3 Commission must properly address: (1) the bifurcation of APS generation between
4 itself and its affiliate, PWEC; (2) recovery by APS of the full costs of preparing for
5 such divestiture; and (3) the restoration of the \$234 million pretax write-off that
6 APS took in reliance on the 1999 Settlement Agreement with the Commission.
- 7 • *Continued vertical integration is a reasonable approach, especially for a utility that*
8 *is in APS' situation.* While it is clear that FERC and many states are pursuing
9 regulatory policies and industry structures that accommodate wholesale
10 competition, this goal can be accomplished while preserving the vertical economic
11 efficiencies and stability that vertical integration can provide.

12 **Q. How is your testimony organized?**

13 A. **Section II** briefly summarizes the history of electricity policy in Arizona as it pertains
14 to the Company and its customers. Important considerations include the regulatory
15 compact in Arizona (including the terms of the 1999 Settlement Agreement) and the
16 events of the last few years in nearby California and the broader Western power
17 markets. The conclusions that I draw in this testimony take these factors into account
18 and are therefore specific to APS' situation (and that of Arizona generally).

19 **Section III** discusses the regulatory compact, regulatory risk, and appropriate
20 regulatory policy when the "rules of the game" are changed. Proper regulation is
21 needed to accommodate wholesale competition, which can be accomplished while
22 maintaining organizational efficiency. As the Commission deals with the effects of its
23 Track A decision, it is very important that the Commission aim to achieve allocative
24 efficiency (where utility rates are set in a way that reflects its economic costs), while
25 also providing the utility with proper opportunities and incentives to achieve productive
26 (technical) efficiency and make the investments that are critical to maintaining
27 reliability over time. The ability of a regulated utility to consistently attract capital is
28 largely a function of the confidence that investors have in a jurisdiction's regulatory
29 compact and therefore it is critically important that prudence and related issues
30 pertaining to new generating units be addressed in a reasonable manner.

31 **Section IV** addresses the nature and potential benefits of vertical integration in the
32 current environment. It also discusses the link between vertical integration and the

1 regulatory compact. I explain why it is important that utilities have the flexibility to
2 achieve organizational efficiency, and I explain that vertical integration is a reasonable
3 way to achieve that goal. I also explain that the meaning of vertical integration has
4 changed with the movement to wholesale competition, which, in particular, requires
5 changes in how transmission is organized and operated.

6 **II. A BRIEF HISTORY OF THE RELEVANT ARIZONA** 7 **CIRCUMSTANCES**

8 **Q. Please describe your understanding of electric policy in Arizona, as it pertains to**
9 **APS.**

10 **A.** While the purpose of my testimony is to provide a policy framework for properly
11 regulating the Company in today's circumstances in Arizona, it is important to briefly
12 describe the circumstances APS finds itself in today.

13 In the U.S., there has been a general movement toward wholesale (and, in some states,
14 retail) competition, going back at least as far as the Energy Policy Act of 1992
15 ("EPAct") and the Federal Energy Regulatory Commission's ("FERC") Orders Nos.
16 888 and 889. The FERC continues to be committed to enabling the development of
17 competitive wholesale power markets.³ In Arizona, the movement to retail (and
18 wholesale) competition has been complicated by institutional and infrastructure
19 circumstances in the state (e.g., the large amount of transmission and generation that is
20 owned by public power entities), as well as transmission limitations.

21 For APS, the 1999 Settlement Agreement, as approved by the Commission, has
22 provisions for: (1) a series of retail rate decreases for residential, commercial, and
23 industrial customers, and the development of rates to accommodate competitive direct
24 access service; (2) a moratorium (under almost all circumstances) on price increases for
25 standard-offer and unbundled competitive direct access service until July 1, 2004; (3) a

³ In its press release announcing its issuance of a white paper on bulk power market design, the FERC emphasized its "strong commitment to customer-based, competitive wholesale power markets, while underscoring an increasingly flexible approach to regional needs and outlining step-by-step elaborations of its key market design proposal." FERC, "Commission introduces White Paper on bulk power market design, focuses on RTOs while citing deference to regional needs," Docket No. RM01-12-000, April 28, 2003.

1 write-off of regulatory assets with a current value of \$234 million; (4) deferral
2 provisions for certain other costs; (5) APS' distribution system was opened for retail
3 access without legal challenge by APS; (6) recovery of some (but not all) potentially
4 stranded costs through a competitive transition charge that remains in place until
5 December 31, 2004; and (7) the transfer of competitive generation assets to a non-utility
6 affiliate at book value no later than December 31, 2002.

7 As is typically the case in regulatory resolutions of this type, the settlement reached by
8 the parties was intended to be taken as a whole, in order to preserve the tradeoffs that
9 had been made among the parties to achieve agreement. Further, I understand that the
10 1999 Settlement Agreement includes language stating that the Commission's electric
11 restructuring rules are to be interpreted and applied, to the greatest extent possible, in a
12 manner consistent with that agreement. In fulfilling its part of the agreement, the
13 Company wrote off about \$234 million (pretax in 1999) of its otherwise recoverable
14 stranded costs. The Commission approved the Settlement, including the provision that
15 explicitly made the Commission a party to the agreement, thereby agreeing to bind itself
16 to its terms.

17 The years subsequent to the Commission's approval of the 1999 Settlement Agreement
18 were, of course, dramatic ones in nearby California and throughout the broader Western
19 power markets.⁴ The California electricity crisis and the broader crisis in Western
20 energy markets during 2000-2001 were major events, with dramatic effects on
21 wholesale electricity markets, the merchant generation industry, and the utilities that
22 generate and/or acquire generation on behalf of their customers, such as APS.⁵

23 As a result of concerns arising out of these unexpected circumstances, in September
24 2002, the Commission issued its Track A Order, which reversed its own decision that
25 had required APS to transfer its generation assets to a separate corporate affiliate (a

⁴ Banc of America Securities, for example, states that "wholesale power markets have dried up, significantly impairing merchant economics and dislocating the [merchant] business model." Banc of America Securities, *Outlook for the Merchant Energy Sector: Shock Treatment—Is the Merchant Business Model Dead or Alive?*, September 2002, p. 1.

⁵ For a survey, see: Paul L. Joskow, "California Electric Crisis," *Oxford Review of Economic Policy*, Vol. 17, No. 3, 2001, pp. 365-388.

1 transaction previously found to be “in the public interest”). The Commission thereby
2 unilaterally modified the 1999 Settlement Agreement, which had authorized APS’
3 transfer of its generating assets, and directed APS to cancel its activities to transfer its
4 generation assets to PWEC (or some other entity).

5 **Q. Where has this left APS and the Commission?**

6 A. APS remains the major electric utility in Arizona with generation, transmission,
7 distribution, and sale functions. Utility regulation of APS continues, with most features
8 of the pre-competitive regulatory world continuing in place. The Commission also,
9 however, remains committed to competition.

10 This subjects APS to conflicting regulatory and market forces. In particular, APS
11 continues to have an *obligation* to serve those customers who have not switched to a
12 competitive generation provider (as well as those who switch back) even though retail
13 customers can (and might again) switch to competitive suppliers, if they wish to do so.⁶
14 This means that APS has an obligation to plan for customers’ future demands and either
15 build or buy the power and energy needed to meet these demands. Given the long lead
16 times and useful lives inherent to utility assets—and the basic fact that the electricity
17 *has* to be there when customers demand it—APS must make significant investments
18 and commitments to meet customer requirements. Thus, APS continues to operate as a
19 (modified) vertically-integrated utility.

20 **III. CONSISTENT REGULATORY COMMITMENT IN AN ERA OF**
21 **TRANSITION**

22 **Q. Has the Commission changed its policy with respect to APS’ divestiture of**
23 **generation?**

24 A. Yes. As previously discussed, the Track A Order modified the 1999 Settlement
25 Agreement, which authorized APS’ transfer of its generating assets, and specifically

⁶ Retail customers can, in principle, choose to take service from a competitive provider, although few (if any) competitors are offering retail service in Arizona at the present time.

1 directed the Company to cancel its activities aimed at transferring its generation assets
2 to PWEC. While I do not comment on the Commission's reasons for this change in
3 policy, given the circumstances it faced when it did so, the Commission decision left
4 open a number of questions that need to be resolved, and left undone steps that need to
5 be taken. In December 2002, APS and Commission Staff agreed that it would be
6 appropriate for the Commission to consider some of these matters as part of APS' next
7 rate case proceeding. Among the issues left to be decided were:

- 8 1. The rate treatment of the generating assets that PWEC had constructed in the
9 expectation of selling to APS and which APS now proposes to move into the
10 Company's rate base.
- 11 2. Appropriate treatment of the \$234 million pretax write-off agreed to by APS as part
12 of the 1999 settlement agreement, which was modified by the Track A Order.
- 13 3. The appropriate treatment of previously expensed costs incurred by APS in
14 preparation for the previously anticipated, but now thwarted, transfer of generation
15 assets to PWEC.

16 Given the Commission's Track A Order, careful consideration needs to be given to
17 carrying out these decisions in a way that both treats the utility's investors fairly and
18 protects consumers from a Western wholesale electric market that is currently
19 undeveloped, while accommodating the continued movement toward effective
20 wholesale competition. An appropriate regulatory contract is adaptable and flexible
21 (within reason) but must also continue to provide the utility with appropriate and
22 adequate compensation for its continued service to customers.

23 **A. Utilities and the Regulatory Compact**

24 **Q. Please briefly explain the basic economic features of the public utility industry.**

25 A. The public utility industry is capital-intensive. In order to provide efficient, safe,
26 adequate, and reliable service to their customers, utilities must have uninterrupted
27 access to capital markets to maintain and upgrade capital facilities. Investor-owners of
28 public utilities must submit to the requirements of capital markets to raise money to
29 provide utility services. In other words, investor-owned utilities can only *attract* capital

1 at a reasonable cost by showing that investors' capital will be repaid at a reasonable rate
2 of return through a transparent system of regulated prices. Under traditional rate-of-
3 return regulation, incorporating the traditional regulatory compact, utilities are assured
4 of a reasonable opportunity to recover their prudent, just, and reasonable costs,
5 including the cost of capital.

6 The historic paradigm whereby vertically-integrated electric utilities with exclusive
7 franchises provide bundled services within distinct franchise service areas has been
8 challenged in recent years. Transmission and distribution ("T&D") system owners have
9 been required to open up access to their networks, allowing competing suppliers of
10 electricity to offer service.

11 **Q. Please elaborate on what you mean when you refer to the regulatory compact?**

12 A. In general terms, the "regulatory compact" is the concatenation of the U.S. Constitution,
13 franchise agreements, federal and state statutes, Commission Rules and Orders, and
14 policy statements. Economists refer to the regulatory compact as an implicit relational
15 contract, meaning that the "regulatory compact" is not written down in the form of an
16 explicit contract; but it is, nonetheless, an intrinsic part of the relationship between the
17 regulated industry on the one hand, and its regulators on the other.

18 Traditionally, an electric utility, required to operate in the interests of customers, has
19 borne an obligation to provide efficient, safe, adequate, and reliable utility services to
20 customers in return for a "franchise" (or some other means of restricting entry to limit
21 competition) and the opportunity to earn a fair rate of return on its invested capital.
22 Utilities have made long-term commitments in generation to meet the needs of
23 ratepayers adequately and reliably. As a regulated firm, the utility must comply with
24 regulatory accounting requirements, abide by price regulations, meet other regulatory
25 requirements (e.g., affiliate interest rules, customer service rules), invest in facilities to
26 meet customer growth in its service territory, and comply with a host of other
27 requirements. The utility, which has a duty to serve its customers, has substantial
28 expertise in making long-term commitments to assure the adequacy and reliability of

the electric grid, and has the responsibility to acquire generating resources, subject to regulatory oversight.

Regulators, acting as an “agent” for customers, seek to ensure that the utility acts prudently and efficiently when providing utility services. Because customers are not fully able to monitor the actions of the utility, regulatory agencies are established to ensure that the utility agent acts in the best interest of customers. Regulators’ primary regulatory “tool” for overseeing the utility is the traditional rate-of-return/cost-of-service rate case, which provides the regulator with a forum for investigating and determining the justness and reasonableness of the utility’s rates. Using a “test year” revenue requirement, the regulatory agency examines the reasonableness of the utility’s sales growth projections, operating expenses, cost of capital, and other cost components, and then sets rates that provide the utility a reasonable opportunity to recover its just and reasonable costs—this is the “heart” of the regulatory compact. While traditional rate regulation does not usually explicitly focus on the utility’s incentives to any great extent, other than through disallowances of imprudent costs, traditional rate regulation does provide incentives via “regulatory lag,” meaning that once rates are set the utility must control its costs and efficiently meet customers’ demand in order to maintain or improve its profitability. Ultimately, through the regulatory process, the utility passes on to customers the benefits of its sole-provider status.

Q. Does the regulatory compact concept apply when, as here, a regulatory agency approves a stipulation?

A. Stipulations are an *explicit* agreement between a utility and the other parties to the settlement agreement. In this case, the Commission both approved and agreed to hold itself to this settlement. In my opinion, the settlement became part of the regulatory compact when it was approved (and joined) by the regulator.

Q. Can a regulator itself unilaterally deviate from the regulatory compact?

A. Not if it expects to retain the confidence of the investment community. A regulator can, of course, alter its own specific rules or other requirements in accordance with whatever

1 procedures are required in that jurisdiction and within the bounds of whatever
2 substantive authority it possesses, but for major changes in requirements that
3 significantly alter previous reasonable expectations, it must compensate the utility for
4 any harm done to it by the change.

5 This is important both for fairness and economic efficiency reasons. Fairness
6 considerations include meeting the reasonable expectation of investors as to the
7 underlying regulatory structure that they were led to believe would be in place for the
8 utility. Put more colloquially, they were presented with assured "rules of the game."
9 From an economic standpoint, regulation can be viewed as a "highly incomplete form
10 of long-term contracting" in which the terms of the regulatory compact adapt to
11 changing circumstances to meet the needs of customers while also ensuring that the
12 utility has the opportunity to earn a fair rate of return.⁷ Fairness requires that costs that
13 are reasonably incurred, but become stranded as a result of change in a regulatory
14 policy should, in recognition of the regulatory compact, be recoverable by the utility. In
15 earlier decisions (such as the 1999 Settlement Agreement), this Commission has
16 recognized this principle.

17 It is particularly important to remember that the regulatory compact does not allow a
18 regulator to change the regulatory rules without appropriate compensation after
19 investments have been made by the utility in good faith reliance on those rules. The
20 problem for investors is that once investments have been made, they become exposed to
21 opportunistic behavior by the regulator, which economists sometimes refer to as
22 regulatory "recontracting" or "holdup." The regulatory compact evolved, in large part,
23 to prevent opportunistic regulatory behavior because fulfilling investors' reasonable
24 expectations ordinarily is in consumers' long run interest. Efficiency considerations
25 include allocative efficiency (utility rates should be set in a way that reflects economic
26 costs), productive (technical) efficiency (the utility should be able to recover prudent
27 costs aimed at providing efficient utility service in rates), and dynamic efficiency (the
28 utility should aim—over time—to make investments that ensure appropriate levels of

⁷ Oliver E. Williamson, *The Economic Institutions of Capitalism* (New York: Free Press, 1985), p. 347.

1 reliability and increase the efficiency of the utility network). With traditional utility
2 regulation, the upside return to the utility is effectively capped at the allowed ROE, an
3 appropriate policy given the presumed essential nature (sole provider status) of the firm.
4 Given this, both economic efficiency and fairness demand that downside risk be capped
5 as well. The ability of a regulated utility to consistently attract capital is largely a
6 function of the confidence that investors have in a jurisdiction's regulatory compact and
7 therefore it is critically important that prudence issues and the overall returns to
8 investors be addressed in a reasonable manner.

9 **B. The Reversal of the 1999 Settlement Agreement**

10 **Q. Does the reversal by the Commission of its approval of the transfer of APS'**
11 **generation to a non-utility affiliate raise important regulatory policy issues?**

12 A. Yes, it does. The Track A order clearly terminates the Company's plans to move its
13 generation from the utility to a non-utility affiliate. Given this major change in one part
14 of the 1999 Settlement Agreement, the equitable outcome, in principle, might seem to
15 be to restore APS and its affiliates to their *status quo* position in 1999. This, however,
16 is not completely possible—after all, APS has already reduced rates to its customers
17 pursuant to the 1999 Settlement Agreement, and PWEC has borne the burden and risk
18 of constructing new generation for APS. To partially deal with this issue, however,
19 APS is filing a rate case to reunify the PWEC generation at APS under a common
20 regulatory scheme.

21 In addition, APS wrote-off certain otherwise recoverable costs pursuant to the 1999
22 Settlement Agreement and then incurred significant additional costs relating to the
23 planned transfer of its generation. Because it was then prohibited from transferring
24 generation to a non-utility affiliate, as a result of the Commission's Track A decision,
25 reasonable regulation, going forward, would restore the assets that had been written off
26 the company's books and allow APS to recover these assets as part of its revenue
27 requirement. Importantly, so far as I am aware, there has been no finding that these
28 costs were not prudent and reasonably incurred. Further, APS should be able to recover

all reasonable costs that it had incurred as a result of the Commission's approval of the plan to transfer its generation assets, including the \$234 million of regulatory assets.

Q. Didn't APS agree in the Settlement to forego one-third of the cost of divesting its generation?

A. As I understand it, that was not part of the original agreement. However, I understand that it is also true that APS did not oppose that change in the provisions of the settlement. But it is equally clear that such acquiescence was premised on the divestiture actually taking place as proposed. It would be adding insult to injury to deny APS divestiture but then hold them to the one-third write-off of divestiture-related costs. This would be like the seller backing out of a deal and then refusing to give back the buyer's down-payment.

IV. VERTICAL INTEGRATION, ORGANIZATIONAL EFFICIENCY, AND REGULATION

Q. Has vertical integration been a commonly-used way to achieve organizational efficiency in the electric utility industry?

A. Yes. Vertical integration was—and, in many cases, continues to be—commonplace in the electric services industry (as well as in telecommunications) because it can economize on transaction costs and facilitate effective coordination and cooperation in operating an interconnected system. For example, it can allow unified decision making with respect to generation and transmission. In 1989, Paul Joskow noted that:

“[t]he combination of economies of scale, multiproduct production, and vertical integration provide the primary public interest rationale for the emergence of vertically integrated utilities with de facto legal monopoly franchises to provide retail service to a specific geographical area, subject to price regulation. . . . regulated integrated monopoly distribution utilities are the efficient institutional response to obtain the cost savings of single-firm production without incurring the costs of monopoly pricing.”⁸

⁸ Paul L. Joskow, “Regulatory Failure, Regulatory Reform, and Structural Change in the Electrical Power Industry,” *Brookings Papers: Microeconomics*, 1989, pp. 139-140.

1 In the telecommunications industry, the incumbent local exchange carriers ("ILECs")
 2 continue to be vertically integrated. In passing the Telecommunications Act of 1996
 3 ("TA 1996"), Congress sought to establish a "pro-competitive, de-regulatory national
 4 policy framework" for the United States.⁹ Rather than disturbing the organizational
 5 structure of the ILECs, TA 1996 focuses on wholesale services that the large ILECs
 6 must provide on a nondiscriminatory basis, including interconnection, unbundling, and
 7 resale requirements. Simply put, federal and state telecommunications policy has gone
 8 down a path of relying on competition and non-structural safeguards to ensure
 9 competition, while allowing the ILECs to retain the economies of scale and scope
 10 associated with vertical integration.

11 **Q. Please summarize the rationale for why firms (in any industry) may choose to**
 12 **vertically integrate.**

13 A. Vertically-integrated firms emerge when a transaction can be completed most
 14 economically through unified ownership (*i.e.*, the buyer and supplier are in the same
 15 enterprise). A basic aspect of vertical integration is the "elimination of contractual or
 16 market exchanges, and the substitution of internal exchanges within the boundaries of
 17 the firm."¹⁰ If vertical integration is chosen over a market exchange relationship,
 18 Williamson argues that it must be "because the contract between collocated stages is
 19 mediated more effectively by hierarchy than by market."¹¹ Williamson also notes that
 20 vertical integration has "the purpose and effect of economizing on transaction costs."¹²
 21 In other words, by achieving economies of scope and scale the utility can increase its
 22 productive (technical) efficiency, which benefits customers.

⁹ Joint Explanatory Statement of the Committee of Commerce, H.R. Rep. No. 458, S. Rep. No. 230, 104th Cong., 2d Sess. at 113 (1996). The Federal Communications Commission cited this language in its *Implementation of the Local Competition Provisions of the Telecommunications Act of 1996*, CC Docket No. 96-98, First Report and Order, 11 FCC Rcd 15499, 1996 (Interconnection Order), ¶ 21.

¹⁰ Martin K. Perry, "Vertical Integration: Determinants and Effects," *Handbook Of Industrial Organization: Volume 1*, edited by Schmalensee and Willig (Amsterdam: North-Holland, 1989), at 185.

¹¹ Oliver E. Williamson, *The Mechanisms of Governance* (New York: Oxford Univ. Press, 1996), p. 16.

¹² *Id.*, p. 85.

1 **Q. Do you have any comments regarding the Commission's decision to require that**
2 **the Company *not* transfer its generation assets either to an unrelated third party**
3 **or to a separate corporate affiliate?**

4 A. My view on divestiture of utility generation has been that divestiture cannot be ruled out
5 as a possible policy option and utilities should not be restricted from considering
6 voluntary divestiture of particular assets as one course of action as they decide how best
7 to operate in a restructured (competitive) market. However, my basic view also is that
8 mandatory divestiture should be a last resort as a regulatory policy, to be used only after
9 less interventionist policies (*i.e.*, functional unbundling and codes of conduct) have been
10 tried.

11 The FERC reached this same conclusion in Order No. 888:

12 [w]e believe that functional unbundling, coupled with these safeguards
13 [*i.e.*, codes of conduct] is a reasonable and workable means of assuring
14 that non-discriminatory open access transmission occurs. In the absence
15 of evidence that functional unbundling will not work, we are not
16 prepared to adopt a more intrusive and potentially more costly
17 mechanism—corporate unbundling—at this time.¹³

18 My primary concern with mandated divestiture and/or separate subsidiary requirements
19 is that it forecloses important opportunities for “organizational efficiency” that can be
20 captured only if firms are free to define and test the effectiveness of their own corporate
21 structures. Stated more simply, it is up to each firm’s management to figure out what
22 the best structure is for their particular firm.

23 **Q. Please explain what you mean by organizational efficiency.**

24 A. An aspect of productive efficiency that warrants special mention is “organizational
25 efficiency”—the concept that a firm’s essential character is not fixed. The range of
26 activities undertaken by a single firm evolves with opportunities and circumstances,
27 based on an efficiency logic, specific to the firm, which is not always apparent to
28 outside observers. Utilities that are given the flexibility to redefine themselves for

¹³ FERC Order No. 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket Nos. RM95-8-000 and RM94-7-001, April 24, 1996, p. 59. 61 Fed. Reg. 21,540 (1996).

1 competition have a good chance of surviving, benefiting both consumers and owners in
2 the new environment, while those that are artificially limited in their ability to adapt are
3 less likely to succeed. Thus, I believe it is very important that the Company have
4 flexibility and discretion to organize itself in an efficient way.

5 **Q. Are utilities moving back to a more traditional vertical integration that ignores the**
6 **existence of competition in wholesale electricity markets?**

7 A. No. The FERC's wholesale competition policies, as set forth in its Orders Nos. 888 and
8 889, have irrevocably changed the way that utilities operate. FERC's Order 2000,
9 which addresses the continuing formation of RTOs and similar institutions, continues
10 the movement toward wholesale competition. Further, the Arizona Commission's
11 efforts to unbundle rates remain in effect. Given these basic facts, electric utilities
12 would not expect to move back to full old-style vertical integration, but can and do
13 integrate a "new-style" vertical integration into this new reality.

14 **Q. Please explain what you mean by "new-style" vertical integration.**

15 A. A new-style vertically-integrated utility can have generation, transmission, distribution,
16 and sale functions but the "lines of demarcation" between these functions will be much
17 clearer than they were when traditional utility vertical integration was the norm.
18 Regulatory rules and institutional structures to support wholesale (and, perhaps, retail)
19 competition in the generation business will be put in place. In the near term, this
20 basically requires implementing a workable transmission structure for the Southwest,
21 via the WestConnect independent transmission group.

22 "New-style" vertically-integrated utilities, operating in competitive wholesale
23 generation markets, will develop a least-cost mix of owned generation, contracts, and
24 market purchases. By having the flexibility to do this, they can capture the
25 "organizational efficiency" benefits to which I previously referred, hedge customer
26 exposure to the market, and yet take advantage of market opportunities and market
27 efficiencies.

1 **Q. How does vertical integration provide benefits to utilities that have an obligation to**
2 **serve?**

3 A. The basic point here is that vertical integration can provide a physical hedge to
4 provider-of-last-resort risk. In other words, it reduces the utilities' exposure to markets
5 or contracts in providing provider-of-last-resort service to customers. This is especially
6 important given the turbulence in energy markets in recent years and the current low-
7 volume state of Western energy markets. Given the current state of wholesale market
8 development in the West and the financial troubles that some merchant generators have
9 faced in recent years,¹⁴ vertical integration is a reasonable way for a utility to protect its
10 customers from volatile wholesale electricity prices. Regulators, of course, need to
11 assure that vertically-integrated utilities are regulated in such a way as to accommodate
12 the development of competitive wholesale electricity markets.

13 **Q. Can such "new-style" vertically-integrated utilities co-exist with regulation and the**
14 **regulatory compact?**

15 A. Absolutely. Vertically-integrated utilities have long been regulated under the regulatory
16 compact. In the new environment, vertically-integrated utilities' rates have been
17 unbundled and functional separation has occurred at FERC, which allows traditional
18 regulation to ensure that the public interest is met while accommodating wholesale
19 competition in the generation market.

20 **Q. Regarding competition in the wholesale market, can "new-style" vertically-**
21 **integrated utilities co-exist with the new competitive environment?**

22 A. Yes. In fact, even the "old-style" vertically-integrated utilities operated in what were at
23 least partially competitive markets for many years. What FERC and certain state
24 policies have done is to expand those competitive market opportunities by removing
25 obstacles to competition. With the clear lines of demarcation of function that I
26 discussed earlier, and appropriate codes of conduct, vertically-integrated utilities can

¹⁴ Banc of America Securities points out that "[t]he capital markets are essentially closed to the cash strapped merchant players, further heightening the risk that these players will not be able to refinance an estimated \$30 billion in debt refinancings over the next two years." Banc of America Securities, *Outlook for the Merchant Energy Sector: Shock Treatment—Is the Merchant Business Model Dead or Alive?*, September 2002, p. 1.

1 serve an important role in such a competitive wholesale market without abandoning the
2 consumer protections inherent in traditional regulation.

3 **Q. Do you have any concluding comments?**

4 A. Yes. Unification of the PWEC generation into a vertically-integrated APS has
5 efficiency-related advantages. Moreover, it would be not be inconsistent with the
6 broader move toward more competition in the wholesale market and would be an
7 important final step in resolving the fallout from the Track A order. It does so in a
8 manner that makes APS and its affiliates whole, or at least significantly closer to whole,
9 for this change in Commission direction and is thus fully consistent with the regulatory
10 compact as I have described it.

11 **Q. Does this conclude your testimony?**

12 A. Yes, it does.

Appendix A

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APPENDIX A

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Dr. Kenneth Gordon, as of April 2001, is a Special Consultant with National Economic Research Associates, Inc. specializing in utility regulation and related issues. Prior to that date, Dr. Gordon was a Senior Vice President with National Economic Research Associates. He was Chairman of the Massachusetts Department of Public Utilities from January 1993 to October of 1995. He came to the Massachusetts Commission from the Maine Public Utilities Commission, where he held the office of Chairman from 1988 through the end of 1992. Prior to that, he was an Industry Economist at the Federal Communications Commission's Office of Plans and Policies. Prior to that, he taught at several colleges since 1965, the most recent position having been at Smith College.

Dr. Gordon was an active member of the National Association of Regulatory Utility Commissioners (NARUC) and served as president of that organization in 1992. He was also a member of the Executive Committee, and the Committee on Communications of NARUC. He has served as Chairman of the New England Conference of Public Utilities Commissioners Telecommunications Committee, and is a former Chairman of the Power Planning Committee of the New England Governors' Conference. He currently also serves on several boards and committees. Dr. Gordon has authored a number of publications and lectures widely on topics related to utility regulation.

Dr. Gordon is a graduate of Dartmouth College and holds a doctorate in economics from the University of Chicago.

EDUCATION

University of Chicago	Ph.D	1973
University of Chicago	M.A.	1963
Dartmouth College	A.B.	1960

EMPLOYMENT

April 2001 -	National Economic Research Associates, Inc., Cambridge, MA <u>Special Consultant</u>
August 1996 - March 2001	National Economic Research Associates, Inc., Cambridge, MA <u>Senior Vice President</u>
November 1995 - July 1996	National Economic Research Associates, Inc., Washington, D.C. <u>Senior Vice President</u>
October 1995	Consulting Economist
January 1993 - October 1995	Massachusetts Department of Public Utilities <u>Chairman</u>
October 1988- December 1992	Maine Public Utilities Commission <u>Chairman</u>
1980 - 1988	Federal Communications Commission, Office of Plans and Policy <u>Industry Economist</u>
1965 - 1980	University and College Teaching (most recently at Smith College)
1963 - 1964	University of Chicago <u>Research Associate</u>

CURRENT APPOINTMENTS AND MEMBERSHIPS

Telecommunications Policy Research Conference

Chair, 1995-1996

Board Member, 1994

Energy Modeling Forum (EMF 15, A Competitive Electricity Industry),

Stanford University

Member

American Economic Association

Transportation and Public Utilities Group, AEA

PAST APPOINTMENTS AND MEMBERSHIPS

National Association of Regulatory Utility Commissioners

Communications Committee, 1990 - 1995

Executive Committee, 1991-1995

President, 1992

New England Conference of Public Utility Commissioners

Power Planning Committee

Chairman

Governor's Electric Utility Market Reform Task Force

Co-Chairman

Boston University Telecommunications Forum

Advisor

Center for Public Resources, Legal Program to Develop

Alternatives to Litigation

Chairman, Utilities Committee

Office of Technology Assessment, Advisory Panel on International Telecommunications Networks

Bellcore Advisory Committee,

Member and Chairman, 1993 to 1996.

ACTIVITIES

Participant in numerous regional and state committees, organizations, and task forces.

Participant in various NARUC/DOE conferences on gas and electricity issues.

Frequent speaker on electric, telephone and environmental issues nationally.

TESTIMONIES

Before the New York State Public Service Commission, on behalf of Rochester Gas & Electric Company, direct testimony regarding the determination of merger-enabled savings. May 16, 2003.

Before the Connecticut Department of Public Utility Control, on behalf of Connecticut Natural Gas Corporation and the Southern Connecticut Gas Company, Docket Nos. 99-09-03PH02, 99-04-18PH03 and 01-04-04, direct testimony regarding the determination of merger-enabled gas cost savings. April 28, 2003.

Before the Iowa Utilities Board, on behalf of Iowa Telecommunications Services, Inc., rebuttal testimony regarding economic support of the company's rate adjustment proposal. August 6, 2002.

Before the Public Utilities Commission of Ohio, on behalf of the Cincinnati Gas & Electric (Company), Case No. 00-813-EL-EDI and 01-2053-EL-ATA, direct testimony on the imposition of a moratorium on minimum stay requirements with respect to switching between default (POLR) service and competitive service. Filed June 4, 2002.

Before the Iowa Utilities Board, on behalf of Iowa Telecommunications Services, Inc., direct testimony regarding economic support of the company's rate adjustment proposal. May 24, 2002.

Before the Florida legislature, on behalf of Bell South (Florida), oral testimony on rate rebalancing issues in telecommunications. Presented on January 30, 2002.

Before the Public Utilities Subcommittee of the Maryland House Environmental Matters Committee, on behalf of Southern Maryland Electric Cooperative and Choptank Electric Cooperative, testimony on affiliate issues relating to cooperatives' participation in non-core markets. Filed January 22, 2002.

Before the Indiana Utilities Regulatory Commission on behalf of Citizens Gas & Coke Utility and Indiana Gas Co., Inc., Case Nos. 37394GC50S1 and 37399GC50S1. Affidavit on why the use of RFP bids as a transfer price is appropriate. Filed December 10, 2001.

Before the Alberta Energy & Utilities Board, on behalf of EPCOR Transmission Inc., rebuttal testimony addressing code of conduct issues. November 2, 2001.

Before the Illinois Commerce Commission on behalf of Commonwealth Edison Company, Docket No. 01-0423, surrebuttal testimony on designing delivery service tariffs in a way that support economic efficiency. October 24, 2001.

Before the Illinois Commerce Commission on behalf of Commonwealth Edison Company, Docket No. 01-0423, rebuttal testimony on designing delivery services in a way that supports economic efficiency. September 18, 2001.

Before the Alberta Energy & Utilities Board, on behalf of Atco Group of Companies, Affiliate Proceeding Before the Alberta Energy and Utilities Board, Testimony of Rebuttal Evidence, submitted August 3, 2001

Before the Massachusetts Department of Telecommunications and Energy, on behalf of Berkshire Gas Company, direct testimony on benefits of incentive ratemaking and policy rational supporting company's plan. July 17, 2001.

Before the New Jersey Board of Public Utilities on behalf of Verizon New Jersey, Surrebuttal Testimony on structural separation and code of conduct issues (Docket No. TO01020095). Filed June 15, 2001 (panel testimony co-sponsored by C. Lincoln Hoewing).

Rebuttal Testimony on behalf of Qwest Corporation, Application of Authority to provide in-region interLATA service (Docket No. INU-00-2). Filed May 23, 2001.

Before the State of New York State Public Service Commission on behalf of Verizon New York (Case No. 00-C-1945): Initial panel testimony on the New York State competitive marketplace. May 15, 2001 (co-sponsored with William E. Taylor).

Before the Commonwealth of Kentucky Public Service Commission on behalf of E.ON AG, Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company, (Case No. 2001-104). Direct testimony on the benefits to consumer's resulting from the acquisition of Powergen by E.ON AG. May 14, 2001.

Before the New York State Public Service Commission on behalf of New York State and Gas Corporation, Affidavit on the proper treatment of proprietary competitive information by regulators. Affidavit filed April 23, 2001.

Before the Virgin Islands Public Services Commission, Government of the Virgin Island of the United States (PSC Docket No. 526) on behalf of Innovative Telephone, Rebuttal testimony regarding rural exemption, request for interconnection for Innovative Telephone. Filed April 10, 2001.

Before the State of New York Public Service Commission on behalf of Energy East Corporation, RGS Energy Group, Inc., New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, and Eagle Merger Corp. Affidavit filed March 23, 2001.

Before the Indiana Utility Regulatory Commission on behalf of PSI Energy, Inc. (IURC Docket No. 41445-S1): Rebuttal testimony on the continued use of a purchased power tracker. Filed February 8, 2001.

Before the Pennsylvania Public Utility Commission on behalf of Verizon PA: Rebuttal testimony on why the structural separation model used in electricity does not apply to telecommunications. October 30, 2000.

Before the State of New York Public Service Commission on behalf of New York State Electric & Gas Corporation (Case 96-E-0891): Rebuttal testimony on market power analyses used in setting the backout credit. October 30, 2000. (Cosponsored with David Kathan.)

Before the Connecticut Department of Public Utility Control, on behalf of Connecticut Natural Gas Corporation (Docket No. 99-09-03, Phase II): Rebuttal testimony on role of incentive ratemaking. October 11, 2000.

Before the New York Public Utilities Commission on behalf of New York State Electric & Gas Corporation (Case 96-E-0891): Direct testimony on whether the backout credit set in a stipulation continues to be proper. October 4, 2000. (Cosponsored with David Kathan.)

Before the Virginia State Corporation Commission on behalf of Appalachian Power d/b/a/ American Electric Power Company (Docket Case No. PUA980020): Direct testimony regarding use of "asymmetric" transfer price rules. Filed September 20, 2000.

Before the Alberta Energy and Utilities Board, on behalf of ATCO Gas, ATCO Pipelines, and ATCO Electric: Direct testimony addressing affiliate issues. August 31, 2000.

Before the Iowa Utilities Board on behalf of Qwest Corporation (Docket No. INV-00-3): Direct testimony on deregulation of local directory assistance services. August 11, 2000.

Before the Connecticut Department of Public Utility Control on behalf of the Southern Connecticut Gas Company (Docket No. 99-04-18, Phase III): Late-filed Exhibit No. 159 (direct testimony) on the proper design of an incentive ratemaking plan. August 11, 2000.

Before the Connecticut Department of Public Utility Control on behalf of Connecticut Natural Gas Corporation (Docket No. 99-09-03 Phase II): Prefiled supplemental testimony addressing incentive rate-making issues. Filed August 11, 2000.

Before the Maine Public Utilities Commission on behalf of Central Maine Power Company. Surrebuttal testimony regarding the proper role of incentive ratemaking. August 10, 2000.

Before the Pennsylvania Public Utility Commission on behalf of Bell Atlantic PA (now Verizon PA): Direct testimony on the costs and problems with structural separation in telecommunications. June 26, 2000.

Before the Maine Public Utilities Commission on behalf of Central Maine Power Company (Docket No. 99-666): Rebuttal testimony on incentive rate-making issues. Filed June 22, 2000.

Before the Connecticut Department of Public Utility Control, The Southern Connecticut Gas Company Bench Request/Late file Exhibit (direct testimony) on proper implementation of incentive ratemaking. May 24, 2000.

Before the Public Utilities Commission of Ohio, on behalf of the Cincinnati Gas & Electric Company (Case No. 99-1658-EL-ETP): Supplemental testimony addressing shopping incentive and market power issues. Filed May 1, 2000.

Before the New York Public Service Commission on behalf of New York State Electric & Gas Corporation (NYSEG). Affidavit on the proper calculation of the billing credit customers would receive that switch. Filed April 20, 2000.

Before the Public Utilities Commission of Ohio, on behalf of the Cincinnati Gas & Electric Company: Direct testimony addressing shopping incentive and market power issues. Filed December 28, 1999.

Before the Federal Communications Commission, on behalf of Virgin Islands Telephone: Comments addressing Federal universal service support in the U.S. Virgin Islands. Filed December 19, 1999.

Before the Connecticut Department of Public Utility Control, on behalf of Connecticut Natural Gas Corp.: Direct testimony on performance based ratemaking. Filed November 8, 1999.

Before the Public Service Commission of Maryland, on behalf of Baltimore Gas and Electric Co., etc.: Reply testimony on "code of conduct" issues. Filed October 26, 1999.

Before the Illinois Commerce Commission, on behalf of Illinois Power Company: Rebuttal testimony addressing the pricing of metering and billing services. Filed October 21, 1999.

Before the Maine Public Utility Commission, on behalf of CMP Group, Inc.: Rebuttal testimony on issues related to acquisition of CMP by Energy East. Filed October 13, 1999.

Before the Illinois Commerce Commission, on behalf of Illinois Power Company: Direct testimony addressing the proper pricing of metering and billing services. Filed October 8, 1999.

Before the Public Service Commission of Maryland, on behalf of Baltimore Gas and Electric Co., etc.: Direct testimony on "code of conduct" issues. Filed October 1, 1999.

Before the Maine Public Utilities Commission, on behalf of Central Maine Power Co.: Direct testimony addressing the proposed alternative ratemaking plan. Filed September 30, 1999.

Before the Michigan Public Service Commission, on behalf of Ameritech Michigan: Direct testimony regarding economic consequences resulting from full avoided cost discount as applied to resale of existing contracts. Filed September 27, 1999.

Before the Public Service Commission of West Virginia, on behalf of Allegheny Power and American Electric Power: Rebuttal testimony on "code of conduct" issues. Filed July 14, 1999.

Before the Maine Public Utilities Commission, on behalf of Central Maine Power Co.: Direct testimony on the acquisition of CMP by Energy East. Filed July 1, 1999.

Before the Public Service Commission of West Virginia, on behalf of Allegheny Power and American Electric Power: Direct testimony on "code of conduct" issues. Filed June 14, 1999.

Before the Illinois Commerce Commission, on behalf of Commonwealth Edison: Rebuttal testimony addressing the design of delivery services tariffs. Filed May 10, 1999.

Before the Subcommittee on Energy and Power, on behalf of National Economic Research Associates: Statement addressing electric restructuring market power issues. Filed May 6, 1999.

Before the New Jersey Public Utilities Board, on behalf of the Edison Electric Institute: Direct testimony on the PUC's draft affiliate relations standards. Filed May 3, 1999.

Before the US District Court, Western District of Pennsylvania, on behalf of Allegheny Energy, Inc.: Expert report on regulatory issues regarding the recovery of stranded costs, filed May 1989

Expert report, on behalf of ICG/Teleport addressing the way in which Denver's ordinance allocates costs among users of public rights-of-way. Filed April 21, 1999.

Before the Ohio Senate Ways and Means Committee, on behalf of the Ohio Electric Utility Institute: Direct testimony regarding restructuring of Ohio electricity industry. Filed April 20, 1999.

Before the Federal Energy Regulatory Commission, on behalf of the Central Vermont Public Service Corporation: Rebuttal testimony regarding CVPSC's reasonable expectation to serve its Connecticut Valley affiliate. Filed April 8, 1999.

Before the Joint Committee on Utilities and Energy, on behalf of the Central Maine Power Company: Direct testimony on rate design for recovery of stranded costs. Filed March 23, 1999.

Before the Illinois Commerce Commission, on behalf of the Commonwealth Edison Company: Direct testimony on Commonwealth Edison's delivery service tariffs. Filed March 1, 1999.

Before the Indiana Utility Regulatory Commission, on behalf of Ameritech Indiana: Direct testimony on interconnection issues between RBOC and independent LECs. Filed February 19, 1999.

Before the Indiana Utility Regulatory Commission, on behalf of Ameritech Indiana: Direct testimony on competitive flexibility and alternative rate plan issues. Filed January 29, 1999.

Before the Rhode Island Public Utilities Commission, on behalf of Bell Atlantic-Rhode Island: Rebuttal testimony regarding economic consequences of granting a request by CTC to assume BA-RI retail contract without customer penalty or termination charges. Filed December 4, 1998.

Before the Michigan Public Service Commission, on behalf of Ameritech Michigan: Surrebuttal testimony regarding interconnection agreement. Filed November 9, 1998.

Before the Michigan Public Service Commission, on behalf of Ameritech Michigan: Direct testimony regarding interconnection dispute with a CLEC. Filed October 20, 1998.

Before the Wisconsin Public Service Commission, on behalf of the Edison Electric Industry: Surrebuttal testimony on utility diversification issues. Filed October 16, 1998.

Before the Wisconsin Public Service Commission, on behalf of The Edison Electric Institute: Supplemental direct testimony addressing DSM issues and electric restructuring. Filed October 13, 1998.

Before the Virgin Islands Public Service Commission, on behalf of the Virgin Islands Telephone Company: Testimony regarding the Industrial Development Corporation tax benefit. Filed October 5, 1998.

Before the Wisconsin Public Service Commission, on behalf of The Edison Electric Institute: Rebuttal testimony addressing affiliate interest issues in a traditional regulatory environment. Filed October 2, 1998.

Before the Wisconsin Public Service Commission, on behalf of The Edison Electric Institute: Direct testimony addressing affiliate interest issues in a traditional regulatory environment. Filed September 9, 1998.

Before the Maine Public Utilities Commission, on behalf of Bell Atlantic-Maine: Declaration describing state regulation and special tariffs filed by Bell Atlantic. Filed August 31, 1998.

Before the Vermont Public Service Board, on behalf of Bell Atlantic-Vermont: Rebuttal testimony regarding economic consequences of granting CTC's request to allow assignment of BA-VT retail contracts without customer penalty or termination charges. Filed August 28, 1998.

Before the Massachusetts Department of Telecommunications and Energy, on behalf of Bell Atlantic-Massachusetts: Direct testimony commenting on economic consequences of CTC's policy of allowing customers to assign service agreements, without customer penalty, on resold basis to CTC. Filed August 17, 1998.

Before the Vermont Public Service Board, on behalf of Bell Atlantic-Vermont: Testimony regarding the economic consequences of granting a request by CTC to assume BA-VT retail contract without customer penalty or termination charges. Filed August 14, 1998.

Before the Illinois Commerce Commission, on behalf of Ameritech Illinois: Direct testimony on rate rebalancing plan. Filed August 11, 1998.

Before the Maine Federal District Court, on behalf of Bell Atlantic: Expert report responding to CTCs anti-competitive claims against Bell Atlantic-North. Filed July 20, 1998.

Before the New Hampshire Public Utilities Commission, on behalf of Bell Atlantic: Direct testimony on petition by CTC to assume contracts that CTC had won for Bell Atlantic when it was an agent. Filed July 10, 1998.

Before the Virgin Islands Public Service Commission, on behalf of VITELCO: Testimony on use of consultants by regulatory commissions; benefits of incentive regulation and treatment of tax benefits. Filed July 10, 1998.

Before the Public Utility Commission of California, on behalf of The Edison Electric Institute: Comments on the enforcement of affiliate transactions rules proposed by the California Public Utility Commission. Filed May 28, 1998.

Before the Public Service Commission of New Mexico, on behalf of Public Service Company of New Mexico: Rebuttal testimony regarding the Commission's investigation of the rates for electric service of PNM. Filed May 6, 1998.

Before the Oklahoma Corporation Commission, on behalf of Southwestern Bell Communications: Reply affidavit regarding SBC's application for provision of in-region interLATA service in Oklahoma. Filed April 21, 1998.

Before the Public Utility Commission of Texas, on behalf of Southwestern Bell Communications: Rebuttal testimony regarding SBC's application for provision of in-region interLATA service in Texas. Filed April 17, 1998.

Before the Public Service Commission of New Mexico, on behalf of the Public Service Company of New Mexico: Direct testimony to address the economic efficiency, equity, and public policy concerning PNM's company-wide stranded costs. Filed April 16, 1998.

Before the Illinois Commerce Commission (Docket nos. 98-00013 and 98-0035), on behalf of The Edison Electric Institute: Rebuttal testimony addressing the adoption of rules and standards governing relationships between energy utilities and their affiliates as retail competition in the generation and marketing of electricity is introduced, filed March 25, 1998. Surrebuttal filed March 11, 1998.

Before the Public Utility Commission of Texas, on behalf of Southwestern Bell Communications: Testimony regarding SBC's application for provision of in-region interLATA service in Texas. Filed February 24, 1998.

Before the Kansas Corporation Commission on behalf of Southwestern Bell Telephone Company: Direct testimony regarding SBC's application for provision of in-region interLATA service in Kansas. Filed February 15, 1998. Rebuttal filed May 27, 1998.

Before the Maine Public Utilities Commission, on behalf of Bell Atlantic - Maine: Testimony regarding the reasonableness of restructuring rates. Filed February 9, 1998.

Before the Arizona Corporation Commission, on behalf of Tucson Electric Power Company: Rebuttal testimony regarding the Commission's rules for introducing competition into the electric industry. Filed February 4, 1998.

Before the Oklahoma Corporation Commission, on behalf of Southwestern Bell Communications: Affidavit regarding SBC's application for provision of in-region interLATA service in Oklahoma. Filed January 15, 1998.

Before the Arizona Corporation Commission, on behalf of Tucson Electric Power Company: Testimony regarding the Commission's rules for introducing competition into the electric industry. Filed January 9, 1998.

Before the Maine Public Utilities Commission, on behalf of Central Maine Power Company: Testimony regarding the Commission's proposed affiliate rules. Filed January 2, 1998.

Before the Indiana Utility Regulatory Commission, on behalf of Ameritech Indiana: Testimony regarding Ameritech Indiana's proposal for an interim alternative regulation plan. Filed October 29, 1997.

Before the Public Utility Commission of Texas, on behalf of Entergy-Gulf States Utilities: Rebuttal testimony regarding Entergy's "Transition to Competition" proposal. Filed October 24, 1997.

Before the Illinois State Senate, "Report on SB 55," on behalf of Illinois Power Company: Report and Testimony on proposed electric industry restructuring legislation in Illinois. Filed October 9, 1997.

Before the Indiana Utility Regulatory Commission, on behalf of Ameritech Indiana: Testimony regarding Ameritech Indiana's proposal for a new alternative regulatory framework. Filed July 30, 1997.

Before the Public Utilities Commission of Ohio, on behalf of Ameritech Ohio: Testimony responding to AT&T's "Complaint against Ameritech Ohio, Relative to Alleged Unjust, Unreasonable, Discriminatory and Preferential Charges and Practices." Filed July 7, 1997.

Before the New Jersey Assembly Policy and Regulatory Oversight Committee, on behalf of Public Service Electric and Gas Company: Testimony regarding transition cost recovery from self generators. June 16, 1997.

Before the New Jersey Board of Public Utilities, on behalf of Public Service Electric and Gas Company: Testimony regarding transition cost recovery from self generators. Filed June 6, 1997.

Before the Federal Communications Commission: Reply Affidavit in support of SBC Communications Inc.'s application to offer interLATA service in Oklahoma. Filed May 27, 1997.

Before the Corporation Commission, on behalf of Kansas Pipeline Partnership: Testimony regarding Purchase Gas Adjustment proceeding for Western Resources, Inc. Filed May 7, 1997.

Before the Public Utility Commission of Texas, on behalf of Entergy-Gulf States Utilities: Supplemental direct testimony regarding Entergy's "Transition to Competition" Proposal. Filed April 4, 1997.

Before the Illinois Commerce Commission, on behalf of Ameritech Illinois: Testimony regarding price cap regulation. filed April 4, 1997

Affidavit: in support of SBC Communications Inc.'s application to offer interLATA service in Oklahoma. Before the Oklahoma Corporation Commission and the Federal Communications Commission. Filed February 20, 1997 (OCC) and April 7, 1997 (FCC).

Before the Federal Communications Commission, on behalf of Ameritech: Reply comments on access reform. Filed February 14, 1997.

Before the Federal Communications Commission, on behalf of Ameritech: Paper on access reform, "Access, Regulatory Policy, and Competition", filed January 29, 1997.

Before the Wisconsin Public Service Commission, on behalf of Ameritech - Wisconsin: Testimony regarding interconnection arbitrations. Filed December 5, 1996.

Before the Public Utility Commission of Texas, on behalf of Entergy-Gulf States Utilities: Testimony regarding Entergy's "Transition to Competition" proposal. Filed November 27, 1996.

Before the California Public Utilities Commission: Rebuttal testimony in support of the joint application of Pacific Telesis Group and SBC Communications Inc. for approval of their merger, (Application No. 96-04-038). November 8-9, 1996.

Affidavit: in support of Florida Public Service Commission's appeal of Federal Communications Commission's interconnection order (CC Docket No. 96-98). September 12, 1996.

Before the New Jersey Board of Public Utilities on behalf of Bell Atlantic - New Jersey: "Economic Competition in Local Exchange Markets," position paper on the economics of local exchange competition filed in connection with arbitration proceedings, August 9, 1996 (with William E. Taylor and Alfred E. Kahn).

Federal Communications Commission (CC Docket No. 96-45) on behalf of BellSouth Corporation, "Comments on Universal Service," (with William Taylor), analysis of proposed rules to implement the universal service requirements of the Telecommunications Act of 1996, filed April 12, 1996.

Before the Senate Committee on Commerce, Science and Transportation on FCC Structure and Function: Suggested Revisions, March 19, 1996.

Before the Federal Communications Commission in the Matter of Pricing for CMRS Interconnection on behalf of Ameritech, March 4, 1996.

Before the Senate Committee on Commerce, Science and Transportation on Telecommunications Reform on behalf of NARUC, March 2, 1995.

Before the House Committee on Energy and Commerce Committee, Subcommittee on Telecommunications and Finance on H.R. 4789, the Telephone Network Reliability Improvement Act of 1992, on behalf of NARUC, May 13, 1992.

Before the Senate Committee on Commerce, Science and Transportation on H.R. 2546, a bill proposing the Infrastructure Modernization Act of 1991, on behalf of NARUC., June 26, 1991.

SPEECHES (partial list)

Remarks before the 1996 Telecommunications Policy Research Conference, "Interconnection Principles and Efficient Competition", Solomon's Island, MD, October 7, 1996.

Remarks before the American Bar Association Section of Antitrust Law, "Charging Competitors and Customers for Stranded Costs: Competition Compatible?" Four Seasons Hotel, Chicago, IL, September 19, 1996.

Remarks before the 1996 EPRI Conference on Innovative Approaches to Electricity Pricing, "Prices and Profits: Perceptions of a Former Regulator," La Jolla, California, March 28, 1996.

Remarks before the Innovative Fuel Management Strategies for Electric Companies Conference sponsored by The Center for Business Intelligence, "Anticipating the Impact of Fuel Clause Reversal on Fuel Management," Vista Hotel, Washington, D.C., March 15, 1996.

Remarks before Electricity Futures Trading Conference, "Electricity Futures Trading: What the States Are Doing," Houston, Texas, March 14, 1996.

Panelist, "Regulatory Panel: Who Has Jurisdiction?" Public Power in a Restructured Industry, Washington, D.C., December 8, 1995.

Participant, "Public Policy for Mergers in a Time of Restructuring," Harvard Electric Policy Group, Crystal City, Virginia, December 7, 1995.

Panelist, Roundtable on "Competitive Markets in Electricity and the Problem of Stranded Assets," Progress and Freedom Foundation, Washington, D.C., December 1, 1995.

Panelist on "The Range of Uncertainty" at the Illinois Electricity Summit, Northwestern University, Evanston, IL., November 28, 1995.

PUBLICATIONS

"Demand Side Management in Today's Electricity Market," *Electricity Deregulation Commentary, Maine Policy Review*, Winter 2001, pp. 19-21.

"Reforming Universal Service One More Time," *Communications Deregulation and FCC Reform: What Comes Next?*, Jeffrey A. Eisenach and Randolph J. May, editors (Washington, D.C.: The Progress & Freedom Foundation, pp. 61-84. Conference Edition, December 2000.

"Back to the Basics: Federal Legislation, Electricity Deregulation," *The Boston Globe*, June 7, 2000.

"Consumer Sovereignty, Branding, and Standards of Competitive Practice," *Electricity Journal*, May 2000, Volume 13, Number 4, pp.76-84 (with Wayne Olson)

"Open Entry, Choice, and the Risks of Short-Circuiting the Competitive Process" prepared for the Edison Electric Institute, March 20, 2000. (with Wayne Olson)

"Getting it Right: Filling the Gaps in FERC's Stranded Cost Policies," *The Electricity Journal*, Volume 12, Number 4, May 1999.

"Choose the Right Recipe for Electric Deregulation," *The Star-Ledger*, December 16, 1998.

Prepared for Edison Electric Institute, "Fostering Efficient Competition in the Retail Electric Industry: How Can Regulators Help Solve Vertical Market Power Concerns? First, Do No Harm," July 22, 1998 (with Charles Augustine).

"The FCC's Common Carrier Bureau: An Agenda for Reform," Issue Analysis Number 62: Citizens for a Sound Economy Foundation, September 26, 1997 (with Paul Vasington).

"What Hath Hundt Wrought?," *Wall Street Journal*, page A18, May 30, 1997 (with Thomas J. Duesterberg).

Book: "Competition and Deregulation in Telecommunications: The Case for a New Paradigm," Hudson Institute, Indianapolis, IN, 1997 (with Thomas J. Duesterberg).

"The Regulators' and Consumer Advocate's Dilemma", *Purchased Power Conference*, Exnet, 1993.

"Public Utility Regulation: Reflections of a Sometime Deregulator", *Public Utilities Fortnightly*, Nov. 1, 1992.

"Utilities as Conservationists: One Regulator's Viewpoint", in *The Economics of Energy Conservation*, proceedings of a POWER Conference, Berkeley, CA, 1992.

"Incentive Regulation in Telecommunications: Lessons for Electric and Gas", in *Incentive Regulation*, Proceedings and Papers, 1992 (Exnet).

Public Utilities Fortnightly, State Regulators' Forum, Contributor since 1992.

"Competition, Deregulation and Technology: Challenges to Traditional Regulatory Process", *In Your Interest*, Minnesota Utility Investor, Inc., 1992.

"Policing the Environment", *Institutional Investor*, October, 1992.

"Regulation: Obstructor or Enabler?", in *Proceedings: Cooperation and Competition in Telecommunications*, Conference sponsored by the Commission of the European Directorate General XIII, Rome, 1993.

"A Basis for Allocating Regulatory Responsibilities", in Clinton J. Andrews, (ed.), *Regulating Regional Power Systems*, Quorum Books, Westport, CT, 1995 (with Christopher Mackie-Lewis).

Book review: Stephen Breyer, *Breaking the Vicious Circle: Toward Effective Risk Reduction*, Harvard University Press, 1992, in Federal Reserve Bank of Boston, *Regional Review*, 1994.

"Weighing Environmental Costs in Utility Regulation: The Task Ahead", *The Electricity Journal*, October, 1990.

"The Effects of Higher Telephone Prices on Universal Service" Federal Communications Commission, Office of Plans and Policy, Working Paper No. 10, March, 1984 (with John Haring).

"Are Recent FCC Telephone Rate Reforms a Threat to Universal Service" in Harry S. Trebing (ed.), *Changing Patterns in Regulation, Markets and Technology: The Effect on Public Utility Pricing*, University of Michigan Press, 1984 (with John Haring).

"A Framework for a Decentralized Radio Service," a staff report of the Office of Plans and Policy, Federal Communications Commission, September, 1983 (with Alex Felker).

"L'impact de la television par cable sur les autres medias" (The Impact of Cable Television on other media in the United State"), *Trimedia*, numero 18019, printemps, 1983 (in French, also reprinted in Spanish).

"FCC Policy on Cable Ownership" in Gandy, Espinosa & Ordovery, (eds.) *Proceedings from the Tenth Annual Telecommunications Policy Research Conferences*, ABLEX, Norward, N.Y., 1983.

"FCC Policy on Cable Crossownership", a staff report of the Office of Plans and Policy, Federal Communications Commission, November, 1981. (With Jonathan levy and Robert S. Preece; I was director of the study.)

"Economics and Telecommunications Privacy: A Framework for Analysis," Federal Communications Commission, Office of Plans and Policy, Working Paper No. 5, December, 1980. (With James A. Brown).

"The Effects of Minimum Wage on Private Household Workers" in Simon Rottenberg, (ed.), *The Economics of Legal Minimum Wages*, American Enterprise Institute, Washington, 1981.

"Deregulation, Rights and the Compensation of Losers," in William G. Shepherd and Kenneth Boyer, eds., *Economic Regulation: A Volume in Honor of James R. Nelson*, University of Michigan Press, 1981. Also circulated as American Enterprise Institute Working Paper in Regulation, 1980.

"Social Security and Welfare: Dynamic Stagnation", *Public Administration Review*, March 1967.

INCIDENTAL TEACHING AND LECTURING

University and College

Yale School of Management and Organization
Harvard Law School, Telecommunications Seminar
Suffolk University Law School
University of Maine
Boston University

Other

Edison Electric Institute
(Electricity Consumers Resource Council)

June 18, 2003